BAYTEX

ENERGY TRUST

2005 ANNUAL REPORT

Year ended December 31 *($ thousands, except per unit amounts)*	2005	2004	CHANGE %
FINANCIAL			
Petroleum and natural gas sales	**546,940**	420,400	30
Cash flow from operations *(1)*	**227,465**	136,012	67
Per unit – basic	**3.38**	2.17	56
– diluted	**3.12**	2.07	51
Cash distributions	**114,221**	113,063	1
Per unit	**1.80**	1.80	0
Net income	**79,876**	16,764	376
Per unit – basic	**1.19**	0.27	341
– diluted	**1.15**	0.26	342
Capital expenditures, net	**152,449**	280,666	(46)
Total net debt	**418,476**	422,044	(1)
Trust units outstanding at December 31 *(thousands)* *(2)*	**71,475**	68,817	4
OPERATING			
Production			
Light oil & NGL *(bbl/d)*	**3,842**	2,172	77
Heavy oil *(bbl/d)*	**21,265**	22,703	(6)
Total oil *(bbl/d)*	**25,107**	24,875	1
Natural gas *(MMcf/d)*	**60.4**	54.9	10
Oil equivalent *(boe/d @ 6:1)* *(3)*	**35,177**	34,022	3
Reserves, proved plus probable *(4)*			
Oil & NGL *(Mbbl)*	**110,255**	93,841	17
Natural gas *(Bcf)*	**176.4**	155.1	14
Oil equivalent *(Mboe @ 6:1)*	**139,657**	119,698	17
Reserve life index *(years, proved plus probable)*	**11.0**	9.1	21

(1) Cash flow from operations and cash flow from operations per unit are non-GAAP terms that represent cash generated from operating activities before changes in non-cash working capital and other operating items. The Trust's cash flow from operations may not be comparable to other companies. The Trust considers cash flow a key measure of performance as it demonstrates the Trust's ability to generate the cash flow necessary to fund future distributions and capital investments.

(2) Number of trust units outstanding includes the conversion of exchangeable shares at the respective exchange ratios in effect at the end of the reporting periods.

(3) Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

(4) Reserves information as at December 31, 2005 and 2004 is prepared in accordance with NI 51-101.

Baytex Energy Trust possesses the attributes required to deliver stable distributions year after year. Quality heavy oil, light crude and natural gas assets are located in three western Canadian provinces and backed by prudent financial and operational management from Baytex's head office in Calgary, Alberta. Baytex Energy Trust units are listed on the TSX (BTE.UN) and on the NYSE (BTE) and have a proven track record of delivering added value and consistent cash distributions to our unitholders.

56%

TOTAL RETURN

For 2005, buoyed by strong commodity prices, Baytex units generated a combined capital growth plus distributions return of 56%.

RAYMOND T. CHAN
President & CEO

2005 was a watershed year. Global supply/demand fundamentals for crude oil, combined with geopolitical tension in key producing regions of the world, drove oil prices to unprecedented levels at a breathtaking pace. Benchmark WTI crude oil began in January around US$42 per barrel, and climbed relentlessly to near US$70 per barrel in September. The 2005 average WTI price of US$56.56 represents a 37 percent increase over the previous record of US$ 41.40 set one year ago. Natural gas prices in North America traded in similar fashion, with NYMEX futures averaging US$8.55 per Mcf and AECO-C spot prices averaging C$8.71 per Mcf during the year, easily eclipsing all previous records. These pricing developments led to apparent general acceptance that high energy prices will prevail in the foreseeable future.

Highlights of the Year

Aided by these favourable conditions, Baytex successfully executed a business plan that added high quality assets with multi-year development potential, as well as building our financial strength to underpin future operations. Highlights of the year include:

- established multi-year, low-cost development inventory at Seal and Stoddart for heavy oil and natural gas, respectively;
- acquired complementary heavy oil assets at Celtic at excellent purchase metrics and added numerous development opportunities;
- completed a $100 million convertible debentures financing which significantly enhanced Baytex's financial flexibility;
- increased cash flow from operations by 56 percent to $3.38 per trust unit;
- maintained monthly distributions at $0.15 per trust unit while reducing payout ratio to 50 percent from 83 percent in 2004;
- achieved finding and development costs of $4.69 per boe and capital investment recycle ratio of 4.7;
- replaced production by 260 percent;
- grew reserves per trust unit by 13 percent to 1.96 boe;
- improved reserve life index by 21 percent to 11.0 years; and
- enhanced net asset value per trust unit by 103 percent to $19.96.

Successful Capital Programs

Capital expenditures during 2005 totalled $152 million, with $130 million spent on exploration and development activities and $22 million spent on acquisitions net of dispositions of assets.

Our internal development program, led by drilling at Stoddart and Seal, was an unequivocal success. Total expenditures incurred of $130 million, though relatively modest at 57 percent of cash flow from operations, replaced 128 percent of our production during the year. This outstanding program was augmented by an excellent acquisition at Celtic, which added 16.5 million boe of heavy oil and natural gas reserves at $1.33 per boe. Our overall finding and development costs of $4.69 per boe and capital investment recycle ratio of 4.7 should place Baytex amongst the best in our industry in 2005. More impressively, we replaced production by 260 percent, increased reserves per trust unit by 13 percent and improved reserve life index by 21 percent, all by spending two-thirds of our cash flow.

The benefits of this capital program will be realized for years to come. At Stoddart, we drilled a total of nine wells during the year, resulting in eight successful natural gas wells with high yields of NGL. Production from this area has grown to over 4,500 boe/d from the 3,300 boe/d at the time of acquisition in December 2004. Baytex has identified approximately 40 future drilling locations in this area, and is planning to drill six of these locations in 2006 to help sustain our natural gas and NGL production. We will continue to grow Stoddart through land purchases and seismic activities commensurate with our increasing knowledge of this area.

At Seal, six horizontal wells drilled in the 2004/05 winter were producing approximately 500 bbl/d. Two horizontal wells and three vertical stratigraphic test wells are being drilled this winter to further delineate this land block, on which Baytex has identified in excess of 100 development locations. Owing to a lack of production infrastructure, current production is being sold at a large discount to market prices for heavy oil in areas with more developed infrastructure. We are working on improving our marketing arrangements before embarking on a large scale development program. We are very excited about the vast potential for development on our 100 sections of land in this area, and are certain that Seal will anchor our heavy oil production needs for the coming years.

In September 2005, we purchased 3,500 boe/d of mainly heavy oil production at Celtic for $69 million. An unsolicited offer in December resulted in Baytex selling the SAGD production just acquired for $45.3 million. Our decision to

acquire these assets was based on the primary (cold) development opportunities which have been retained by Baytex. Production from the retained assets has grown to a current rate of over 3,000 boe/d from the original 1,750 boe/d at the time of acquisition. An active capital program has been planned for this area in 2006, including the drilling of 30 wells. This acquisition complements existing operations in our core area of Tangleflags and provides numerous low cost development opportunities.

Record Financial Results

Oil and gas production during 2005 averaged 35,177 boe/d, an increase of 3 percent over the prior year. Combined with a 25 percent increase in average wellhead oil price and a 27 percent increase in average wellhead gas price, cash flow from operations for the year set a record at $227 million, representing an increase of 67 percent over that of 2004.

The rapid ascent of oil prices from an average of US$31.04 for WTI crude in 2003 to US$56.56 in 2005 resulted in Baytex incurring significant losses from its hedging program. Losses from WTI derivative contracts in 2005, although an improvement over the $82 million incurred in 2004, totalled $48 million. With the expiry of these low price contracts at the end of 2005, Baytex looks forward to reporting financial results in 2006 that, for the first time since our inception as an income trust, reflect the true cash flow capacity of our production base.

During the year, Baytex maintained its monthly distributions at $0.15 per unit. Despite the significant hedging losses incurred, payout ratio in 2005 improved to 50 percent from 83 percent one year ago. The low payout ratio in 2005 brought our cumulative payout ratio since inception to the end of 2005 to a more sustainable 65 percent.

Total debt at year-end 2005 was $418 million, including $74 million of convertible debentures issued in June 2005, with a conversion price of $14.75 per trust unit. As of the end of February 2006, $45 million of the original issue of $100 million of these debentures had been tendered for conversion. The majority of our remaining debt is in the form of US$ denominated senior subordinated term notes maturing in 2010. Baytex has excellent financial flexibility as outstanding revolving bank debt amounts to less than half a year of current cash flow.

Promising 2006 Outlook

Our exploration and development capital budget for 2006 is initially set at $105 million, with 60 percent of it allocated to heavy oil activities and 40 percent to natural gas and light oil activities. One of our biggest challenges in 2006 is

controlling our cost structure in an inflationary environment caused by record demand for properties and services. Our production target for the year is 35,000 boe/d, comprising 21,000 bbl/d of heavy oil, 3,800 bbl/d of light oil and NGL and 61.2 MMcf/d of natural gas. No acquisition or disposition is included in this capital budget.

We have increased our monthly distributions in 2006 to $0.18 per unit. Under current commodity prices, and with the expiry of the low price derivative contracts at the end of 2005, we expect cash flow from operations during 2006 to be sufficient to fully fund our cash distributions and exploration and development capital expenditures. In addition, our financial flexibility will allow Baytex to continue to pursue other opportunities to further enhance value for unitholders.

The New York Stock Exchange (NYSE) has approved our application for the listing of our trust units, with trading expected to commence in late March 2006. Baytex has been a reporting issuer in the United States since the issuance of our senior subordinated term notes. We believe that the NYSE listing will improve the trading liquidity of our trust units and further enhance future access to the capital markets in the United States.

Baytex trust units delivered a price appreciation and cash distribution combined return of 56 percent during 2005, ranking us as a top quartile performer amongst all oil and gas royalty and income trusts. Although our returns have outperformed our peer group and all relevant indices since our inception, our trust unit price is still relatively under-valued based on parameters such as enterprise value to debt-adjusted cash flow, and trading price to net asset value. Accordingly, with improving assets and operating metrics, as well as continuous prudent financial practices, Baytex is confident that it will again outperform in 2006.

On behalf of the Board of Directors

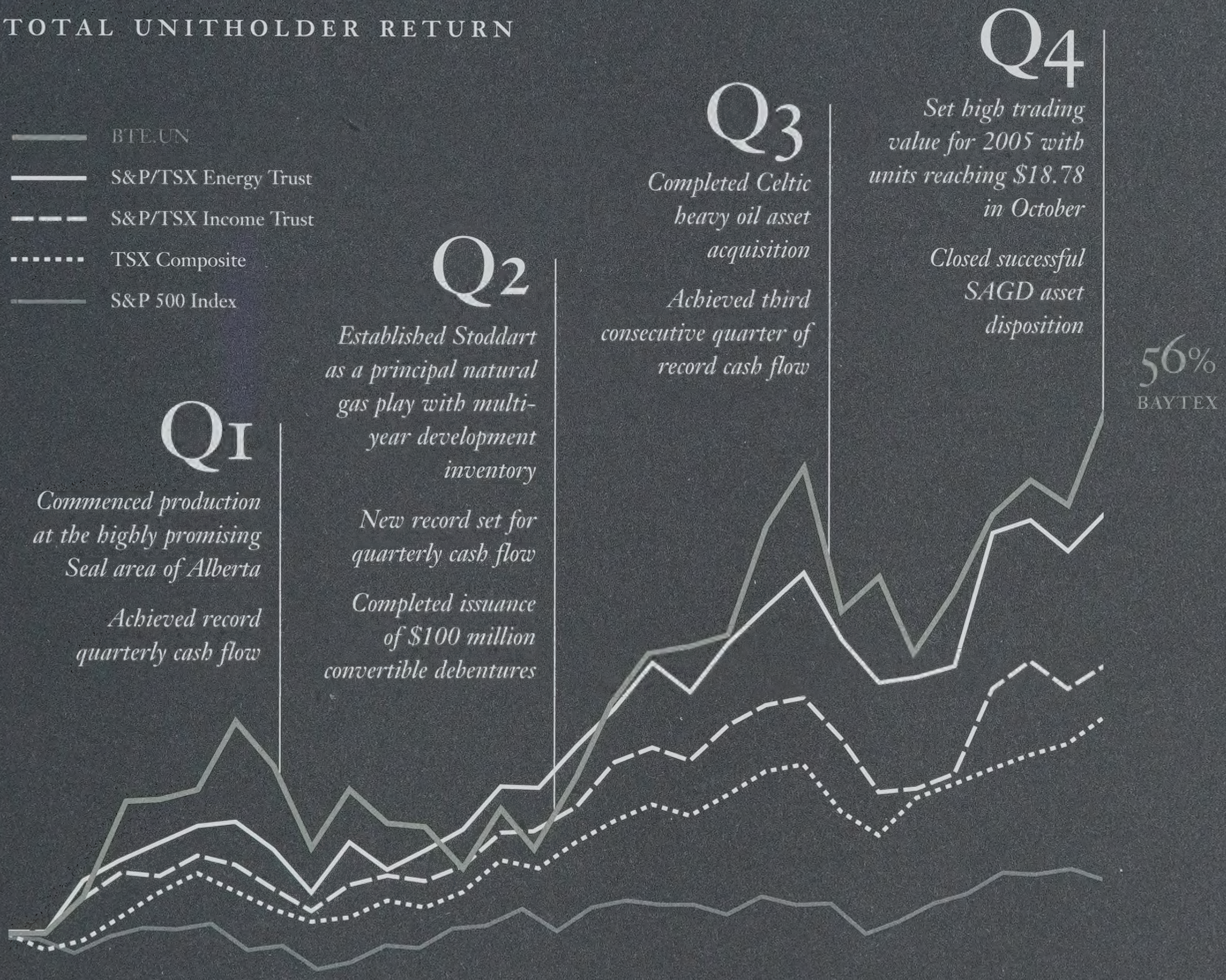
Raymond T. Chan, CA
President and Chief Executive Officer

March 8, 2006

2005 ACHIEVEMENTS

Growth was reflected in cash flow, production, and reserves additions. Efficiency was demonstrated by industry-leading finding and development costs and capital investment recycle ratio. While growth is not surprising against record-high product prices in 2005, adding value plus generating solid prospects for the future in an inflationary climate are notable accomplishments to highlight a successful 2005.

TOTAL UNITHOLDER RETURN



CASH FLOW PER UNIT

$0.67

Q1 distributions of $0.45 per unit were 66% of cash generated.

$0.75

Q2 distributions were 58% of cash flow reflecting price improvements in both oil and gas.

$1.00

Cash flow was at its highest level in Q3, dropping the payout ratio to 41%.

$0.95

At 44% payout in Q4 and a 2005 average of 50%, distribution is at a strong, sustainable level

DRILLING SUCCESS

Solid drilling programs at Stoddart and Seal will generate additional long-term opportunities.

92% SUCCESS

CELTIC TRANSACTION A HIGHLIGHT

The Celtic purchase late in 2005 for net $23.7 million added 1,750 boe/d which has increased to more than 3,000 boe/d in early 2006.

71% INCREASE

CAPITAL EFFICIENCY

While only investing 57 percent of cash flow in E&D, 2005 production was more than replaced, reflecting efficient capital investment.

128% REPLACED

SUSTAINABLE CASH PAYOUT LEVEL

A strong year for cash generation resulted in a payout ratio reduced substantially from 83 percent in 2004.

50% PAYOUT

FINANCIAL FLEXIBILITY

$120+ million in undrawn bank facility to pursue value-creating opportunities.

>$120 MILLION

DELIVERING SUPERIOR RETURN TO UNITHOLDERS

With the cash flow outlook strong, Baytex increased 2006 distributions from $0.15 to $0.18 per unit per month.

$2.16/UNIT

Our asset portfolio offers a higher degree of diversification by product type than is typical of energy trusts. This diversification is valuable for risk management and, ultimately, sustainability. Approximately 60 percent of our production and half of our cash flow is provided by our heavy oil properties, with the remainder from our light oil and natural gas assets.

$227.5

MILLION IN TOTAL CASH FLOW

Record cash flow in 2005 was derived equally from heavy oil and a combination of light oil, natural gas and NGL sales. With a balanced contribution from each of our operating districts, Baytex has a diversified base of cash-generating assets.

REVIEW OF PROPERTIES

Baytex is organized into two operating districts, Heavy Oil and Light Oil/Natural Gas, to develop specific expertise in production and development of each product type. These two districts are in turn comprised of a total of nine geographically-based operating teams. Our philosophy is that, over the long term, success in this industry will be determined by the ability of the company to create real value through technical work on oil and gas assets. Accordingly, Baytex has a full complement of technical professionals (engineers, geoscientists and landmen) staffing each operating team.

Heavy Oil

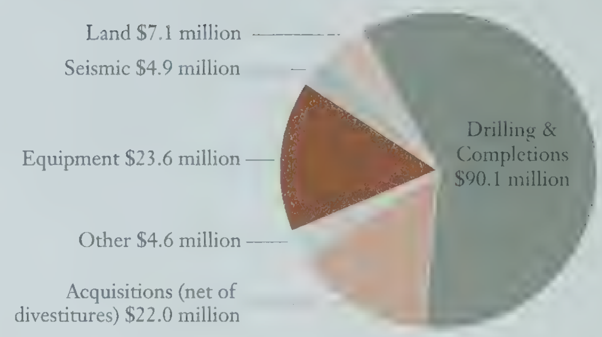
Maintaining a significant emphasis on heavy oil provides a number of advantages to Baytex. First, finding and development costs are typically lower than for light oil and natural gas. To a significant degree, this finding and development cost advantage offsets the lower price received for the heavy oil product. As a result, rates of return on heavy oil investments are comparable to, or in excess of, rates of return on light oil and natural gas investments. In addition, there are fewer competitors with expertise and operating infrastructure in heavy oil than in light oil and natural gas. Consequently, when considering heavy oil acquisitions or mineral leasing opportunities, Baytex has a greater ability to execute highly accretive transactions such as the Celtic acquisition in the fourth quarter of 2005. Finally, because of the large resource base and low development cost associated with heavy oil properties, Baytex has the capability to maintain its production and cash flow while continuing to make significant distributions to unitholders.

Baytex's heavy oil assets are geographically focused in two areas: the Lloydminster area straddling the Alberta-Saskatchewan border and the Peace River oil sands area in northern Alberta. This geographic concentration has allowed Baytex to develop specific expertise in heavy oil production in these areas and to maximize operating and infrastructure economies.

2005 CAPITAL INVESTED

Total: $152.4 million

BY ACTIVITY



BY DISTRICT

ANTHONY MARINO
CHIEF OPERATING OFFICER

Mr. Marino is responsible for the oil and gas operations of the Trust, providing strategic direction over the current and future development of Baytex's asset base.

The Celtic field in southwest Saskatchewan, acquired late in 2005, is typical of Baytex's approach to heavy oil production. We buy or discover heavy oil fields with large oil resources in place and apply our expertise in drilling and producing wells by cold production methods. Net of divestiture of the thermally-enhanced heavy oil production from this field at year-end, Baytex paid \$23.7 million for 1,750 boe/d of primarily cold heavy oil production. After investing approximately \$8 million into new wells and workovers of existing wells, production at the end of February 2006 increased to over 3,000 boe/d. With 16 million barrels of oil equivalent proved plus probable reserves, the Celtic field will be a source of production and cash flow for years to come.

The Seal field in the Peace River oil sands region of northern Alberta will be another source of production growth for Baytex over the long term. Seal is a heavy oil field with unusually high per well productivity and, correspondingly, low development and operating costs per boe. Early in 2006, Baytex is producing approximately 500 bbl/d from six wells at Seal. The developed area encompasses approximately one-half square mile out of 100 square miles of long-term oil sands leases held by Baytex. Based on the test well data obtained thus far, we estimate that each square mile averages approximately 50 million barrels of oil resource in place, of which approximately three percent may prove recoverable under cold primary recovery methods. Thermally-enhanced oil recovery processes could result in considerably higher recovery rates. As of year-end 2005, Baytex has booked only four million barrels of proved and probable reserves at Seal. The Seal field provides relatively low wellhead oil pricing as a result of its distance from connections to heavy oil pipelines. However, due to the large oil resource in the region, infrastructure is rapidly expanding. Baytex intends to conduct a judiciously-paced development program, including drilling several delineation wells during 2006, and a larger scale development drilling program in 2007 as pipeline infrastructure reaches the area.

In addition to Celtic and Seal, Baytex has several significant heavy oil properties in central eastern Alberta and central western Saskatchewan, with production totaling approximately 17,500 bbl/d of oil. Major assets include the Ardmore, Carruthers and Tangleflags fields. These properties have been key contributors to the Trust since its inception. Their large heavy oil resource and well-developed operating infrastructure provide Baytex with ample project inventory to replace heavy oil production at low unit cost for the foreseeable future.

Light Oil and Natural Gas

Baytex has a growing suite of opportunities in its light oil and natural gas properties. Over the past two and a half years, Baytex has increased its light oil and natural gas production by 2,000 boe/d to approximately 14,000 boe/d. Moreover, the geographic scope of our light oil and gas operations has expanded to include northeast British Columbia, providing exposure to one of the most prospective areas for natural gas production in North America.

PERSPECTIVE

"Our approach is to apply a full complement of technical professionals to each of our major assets. This technical focus, in concert with the quality and diversification of our asset base, creates the potential to fully fund our distributions and capital program out of cash flow and to generate projects for years to come."

The Stoddart field in northeast British Columbia is another example of the Trust's ability to add value to an acquired producing asset through strong technical work. Baytex acquired this gas-concentrated asset producing 3,300 boe/d in December 2004 for $90 million. Baytex shot a 16 square-mile, 3D seismic program in 2005 and began a geophysically-targeted drilling program that has yielded 10 producing wells at an 83 percent success rate. Since acquisition, Stoddart has produced operating cash flow of more than $55 million for Baytex, and after re-investment of $30 million, is now producing 4,600 boe/d. Baytex has identified another 40 drilling locations, providing a multi-year stream of natural gas investment opportunities.

Baytex has several other focus areas to underpin its light oil and natural gas production. In northern Alberta, Baytex conducted a 10-well drilling program in winter-only access areas during the winter of 2005/2006. In central Alberta, Baytex initiated a coalbed methane delineation program in both the Horseshoe Canyon and Mannville formations which we expect will ultimately provide a large inventory of high reserve life index investment opportunities.

New Ventures

Baytex has initiated a grassroots exploration program to add new field areas, primarily targeting light oil and natural gas. We are emphasizing raw land acquisition adjacent to existing operating core areas of the Trust. The prospects generated will be at the lower-risk end of the exploration spectrum as defined by probability of success and well cost. Our objective is to add two high-quality exploration plays to our investment portfolio each year. We believe this grassroots program will enhance our long-term sustainability and growth by providing light oil and natural gas inventory to complement producing property acquisitions.

Throughout this report, where we disclose reserves for particular properties, the estimates of reserves and future net revenues for individual properties may not reflect the same confidence level as estimates and future net revenues for all properties, due to the effects of aggregation.

739,50

ACRES *With a substantial undeveloped land base, Baytex is in an excellent position to exploit and develop key areas for the future.*

O

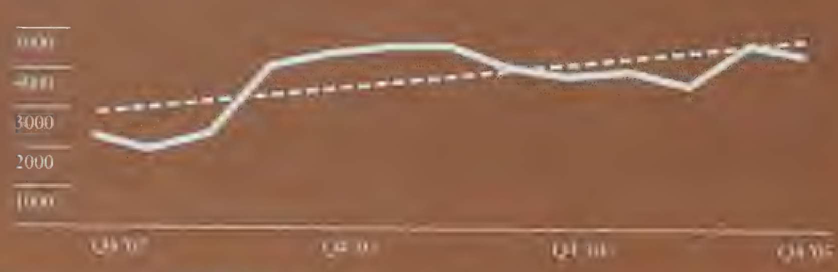
MULTI-DISCIPLINED TEAMS

Our expertise is organized by geographic area and product type so that all of our prospect areas have dedicated teams with all technical disciplines represented. This specialization targets maximum recovery at the most efficient cost.

2005 Performance	*Heavy Oil District*	*Light Oil & Natural Gas District*
Land *(net undeveloped acres)*	313,900	425,600
Production *(boe/d)*	22,515	12,662
% Oil	95	30
% Natural gas	5	70
Wells drilled *(gross/net)*	67/65	51/42
Drilling success rate % *(gross/net)*	96/95	88/88

FOCUS: HEAVY OIL

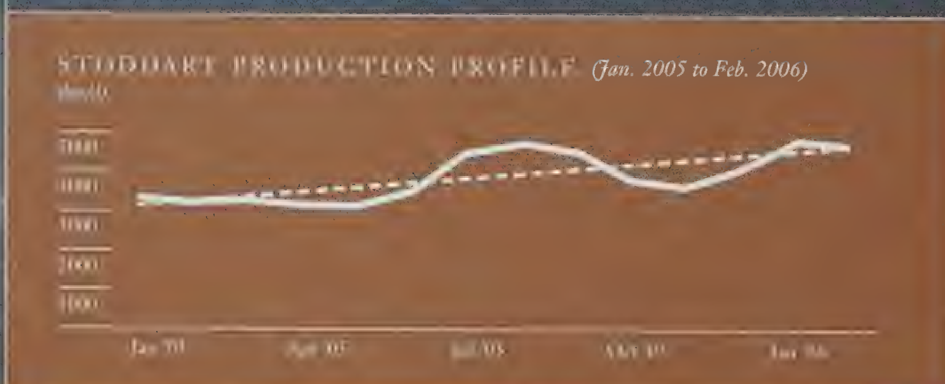
ARDMORE PRODUCTION PROFILE *(2002 through 2005)*
(boe/d)



ARDMORE: A keystone asset accounting for 20% of Baytex's heavy oil production, which illustrates Baytex's heavy oil expertise.

- *Acquired in October 2002 for $33 million with 2,500 boe/d of production*
- *Current production: 4,000 boe/d with operating costs at $5.50 per boe*
- *Finding and development cost: $6.00 per boe*
- *2005 wells drilled: 16 wells at an average cost of $350,000 per well drilled, completed and tied-in*
- *Future identified locations: 20 of which only 8 to 10 will be drilled in 2006*
- *Proved plus probable reserves as at December 31, 2005: 8.5 million boe*
- *Technology: Cold heavy production at an average drilling depth of 450 meters*
- *Overall project capital efficiency since acquisition: $12,400 per boe/d*

FOCUS: LIGHT OIL & NATURAL GAS



STODDART: A natural gas/light oil success story for Baytex, located in northeast British Columbia, one of the most prospective areas for gas in North America.

- *Acquired in December 2004 for $90 million with 3,300 boe/d of production*
- *Current production: 4,600 boe/d with operating costs at $6.30 per boe*
- *Finding and development cost: $10.00 per boe*
- *Cumulative wells drilled: 12 wells (83% success) at a cost of $2 million per well drilled, completed and tied-in*
- *Future identified locations: 40 of which only 6 will be drilled in 2006*
- *Proved plus probable reserves as at December 31, 2005: 12.8 million boe*
- *Technology: Hydraulically-fractured wells at an average drilling depth of 1,700 meters*
- *Overall project capital efficiency since acquisition: $19,800 per boe/d*

FOCUS: OIL & GAS RESERVES

Drilling success and acquisitions combined with strong commodity pricing increased reserves 17 percent to 140 million boe and extended the reserve life index of the Trust to 11.0 years. Reserves per trust unit increased 13 percent to 1.96 boe.

$/BOE OF PROVED PLUS PROBABLE RESERVES ADDITIONS

4.69

Low finding, development and acquisition costs reflect an efficient use of capital and an ability to execute opportunistic transactions.

RESERVES

Oil and Gas Reserves

Reserves levels and the costs required to replace reserves are key measures of an oil and gas entity's sustainability and capital effectiveness. By both measures, Baytex's performance in 2005 was exceptional. Our reserve life index increased significantly and our reserves replacement costs were among the lowest in the industry.

Our 2005 reserves report demonstrates the following achievements of Baytex:

- Total proved reserves increased 20 percent to 101 MMboe and total proved plus probable reserves increased 17 percent to 140 MMboe.
- Production was replaced 235 percent on a proved basis and 260 percent on a proved plus probable basis.
- Finding, development and acquisition (FD&A) costs were \$5.19 per boe proved and \$4.69 per boe proved plus probable before future development capital (FDC) and \$8.45 per boe proved and \$7.69 per boe proved plus probable including FDC.
- Capital investment recycle ratio of 4.7 is among the leaders in our sector.
- Reserve life index based on total proved plus probable reserves increased 21 percent to 11.0 years from 9.1 years in 2004.
- Reserves per trust unit increased 13 percent to 1.96 boe from 1.74 boe one year ago.
- Net present value of total proved plus probable reserves, discounted at 10 percent before tax, increased 75 percent from 2004.
- Net asset value increased 103 percent to \$19.96 per unit from \$9.84 per unit in 2004 on a proved plus probable basis due to higher reserves volumes and value.

These are outstanding results which speak to the quality and sustainability of the Baytex property portfolio and our ability to efficiently add value to our assets. All of Baytex's reserves were evaluated by our independent reserves engineers, Sproule Associates Limited, in accordance with the requirements of National Instrument 51-101.

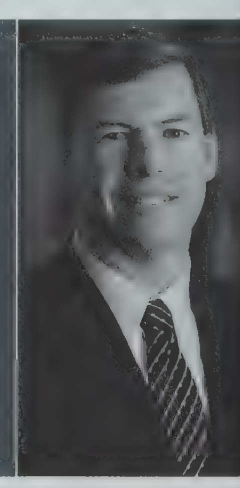
260%

PRODUCTION REPLACEMENT

Not only was 2005 an active drilling year with 118 wells drilled at a 92 percent success rate, but a rich drilling inventory will support active programs for many years.

RANDY BEST
VICE PRESIDENT, CORPORATE DEVELOPMENT

Mr. Best is responsible for asset and corporate acquisitions and divestitures as well as being the corporate reserves officer.



Finding, Development and Acquisition Costs

	2005	2004	2 Year Total
Capital expenditures *($ million)*	**152.4**	280.7	433.1
Heavy oil/Light oil and natural gas spending	**58%/42%**	25%/75%	36%/64%

	Proved			*Proved plus Probable*		
($/boe)	**2005**	2004	*2 Year Weighted Average*	**2005**	2004	*2 Year Weighted Average*
Excluding future development costs						
Finding and development costs	**8.94**	12.61	10.20	**8.16**	9.58	8.71
Acquisition costs (net of dispositions)	**1.48**	14.40	7.51	**1.33**	11.37	6.34
Finding, development and acquisition costs	**5.19**	13.75	8.71	**4.69**	10.70	7.38
Including future development costs						
Finding and development costs	**13.50**	14.98	14.02	**12.38**	12.19	12.33
Acquisition costs (net of dispositions)	**3.46**	15.91	9.27	**3.13**	12.62	7.86
Finding, development and acquisition costs	**8.45**	15.58	11.38	**7.69**	12.46	9.83

The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.

NI 51-101 requires that, where disclosure of finding and development costs is made, the disclosure includes results for the cost of proved and proved plus probable reserve additions including future development costs, but excluding acquisition costs. Additional disclosure is made including the impact of net expenditures on acquisitions in order to provide a more complete reflection of the capital investment activity of the Trust.

Net Asset Value

The following net asset value calculation utilizes what is generally referred to as the "produce-out" net present value of Baytex's oil and gas reserves as evaluated by independent evaluators. It does not take into account the possibility of Baytex being able to recognize additional reserves in its existing properties beyond those included in the 2005 year-end report.

PERSPECTIVE

"Acquisitions and divestitures are opportunistic in nature, and Baytex is fortunate to have a multi-year internal development inventory which allows us to be patient in identifying and executing high value transactions."

	Discounted at 10%	
(million)	*Forecast Prices*	*Constant Prices*
Proved plus probable reserves *(1)*	$ 1,784.7	$ 1,932.6
Undeveloped land *(2)*	96.1	96.1
Net debt *(3)*	(349.9)	(349.9)
Net asset value	$ 1,530.9	$ 1.678.8
Total trust units outstanding *(4)*	76.7	76.7
Net asset value per trust unit	$ 19.96	$ 21.89

Notes:

(1) As evaluated by Sproule Associates Limited as at December 31, 2005. Net present value of future net revenue does not represent fair market value of the reserves.

(2) As evaluated by Baytex as at December 31, 2005 on 740,000 net acres of undeveloped land.

(3) Long-term debt net of working capital as at December 31, 2005, excluding convertible debentures and $5.2 million of notional assets associated with the mark-to-market value of derivative contracts.

(4) Includes 69,283,369 trust units, 1,597,028 exchangeable shares converted at an exchange ratio of 1.37201 and 5,230,644 trust units issuable on the conversion of the $77.2 million outstanding convertible debentures as at December 31, 2005.

The following Management's Discussion and Analysis ("MD&A"), dated March 8, 2006, should be read in conjunction with Baytex Energy Trust's (the "Trust" or "Baytex") audited consolidated financial statements for the fiscal years ended December 31, 2005 and 2004. Per barrel of oil equivalent ("boe") amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil.

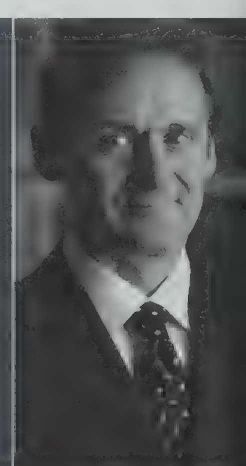
The Trust evaluates performance based on net income and cash flow from operations. Cash flow from operations and cash flow per unit are not measurements based on generally accepted accounting principles ("GAAP"), but are financial terms commonly used in the oil and gas industry. Cash flow represents cash generated from operating activities before changes in non-cash working capital, deferred charges and other assets and deferred credits. The Trust's determination of cash flow may not be comparable with the calculation of similar measures for other entities. The Trust considers it a key measure of performance as it demonstrates the ability of the Trust to generate the cash flow necessary to fund future distributions to unitholders and capital investments.

The Trust also uses certain key performance indicators and industry benchmarks such as operating netbacks ("netbacks"), finding, development and acquisition costs ("FD&A"), recycle ratio and total capitalization to analyze financial and operating performance. These key performance indicators and benchmarks as presented do not have any standardized meaning prescribed by Canadian GAAP and therefore may not be comparable with the calculation of similar measures for other entities.

This discussion and analysis contains forward-looking statements relating to future events or future performance. In some cases, forward-looking statements can be identified by terminology such as "may", "will", "should", "expects", "projects", "plans", "anticipates" and similar expressions. These statements represent management's expectations or beliefs concerning, among other things, future operating results and various components thereof or the economic performance of the Trust. The projections, estimates and beliefs contained in such forward-looking statements necessarily involve known and unknown risks and uncertainties, including the business risks discussed in the MD&A as at and for the years ended December 31, 2005 and 2004, which may cause actual performance and financial results in future periods to differ materially from any projections of future performance or results expressed or implied by such forward-looking statements. Readers should not place undue reliance on any such forward-looking statements, which speak only as of the date they were made.

DEREK AYLESWORTH
CHIEF FINANCIAL OFFICER

Mr. Aylesworth is responsible for Baytex's capital markets, financial reporting and compliance, financial risk management as well as the tax and treasury functions.



The Trust is not obligated to publicly update or revise the forward-looking statements relating to future events or future performance to reflect any change in management's expectations or events.

Baytex Energy Trust (the "Trust") was established on September 2, 2003 under a Plan of Arrangement. The Trust is an open-ended investment trust created pursuant to a trust indenture. Subsequent to the Plan of Arrangement, Baytex Energy Ltd. (the "Company") is a subsidiary of the Trust.

Prior to the Plan of Arrangement, the consolidated financial statements included the accounts of the Company and its subsidiaries and partnership. After giving effect to the Plan of Arrangement, the consolidated financial statements have been prepared on a continuity of interests basis which recognizes the Trust as the successor to the Company. The consolidated financial statements include the accounts of the Trust and its subsidiaries and have been prepared by management in accordance with Canadian generally accepted accounting principles.

2005 OVERVIEW

On June 6, 2005 the Trust issued $100 million principal amount of 6.5% convertible unsecured subordinated debentures for net proceeds of $95.8 million. The debentures pay interest semi-annually and are convertible at the option of the holder at any time into fully paid trust units at a conversion price of $14.75 per trust unit. The debentures mature on December 31, 2010 at which time they are due and payable. The net proceeds were used to reduce outstanding bank indebtedness.

On September 30, 2005 we completed the acquisition of certain heavy oil producing properties in the Celtic area in Saskatchewan for a net cash consideration of $69 million. The assets acquired consisted of 3,350 bbl/d of heavy oil (13 – 15 API) and 0.9 MMcf/d of natural gas. Production from this acquisition represented approximately 10 percent of our existing production. The assets acquired also included approximately 7,500 net acres of undeveloped land. The Celtic properties are situated approximately 30 miles east of Lloydminster and are adjacent to Tangleflags, Baytex's second largest producing area within its heavy oil operations. The expanded Celtic/Tangleflags operating region will improve economies of scale and allow for better control over costs. The acquisition also included in excess of 100 opportunities for development drilling and recompletions for additional primary (cold) heavy oil production and natural gas production which added immediate low-cost development inventory. The acquisition also included 1,750 bbl/d of SAGD (steam assisted gravity drainage) production, representing Baytex's first steam-assisted enhanced recovery project. As part of this transaction, Baytex has entered into a price-sharing arrangement and a net profits agreement for future SAGD development with the vendor with respect to the assets acquired.

On December 30, 2005 we sold the recently acquired SAGD assets in the Celtic area of Saskatchewan for a net cash consideration of $45.3 million. These proceeds were used to repay bank borrowings.

PERSPECTIVE

"The financial position of Baytex has never looked brighter. Our 2006 cash flow is protected with solid commodity price contracts, we have an inventory which allows us to replace production inexpensively, and our balance sheet offers us much financial flexibility."

PROPERTY REVIEW

Principal Properties

Baytex's crude oil and natural gas operations are organized into two operating districts – the Heavy Oil District and the Light Oil and Natural Gas District. Each district has an extensive portfolio of operated properties and development prospects with considerable upside potential. Baytex has established several geographically-organized teams with a full complement of technical professionals (engineers, geoscientists and landmen) within each district. Each team has a mandate to apply its specific knowledge and expertise to its operating area. This focused approach aids in the evaluation and execution of exploration, development and acquisition opportunities and improves cost efficiency.

Heavy Oil District

The Heavy Oil District accounts for approximately 60 percent of current production, three-quarters of oil-equivalent reserves and one-half of cash flow from operations. Baytex's heavy oil operations consist largely of cold primary production, without the assistance of steam injection. In some cases, heavy oil reservoirs containing lower-than-average viscosity crudes are waterflooded, occasionally with hot water. Baytex's heavy oil fields often have multiple productive zones, some of which can be commingled within the same producing wellbore. Production is generated from vertical, slant and horizontal wells using progressive cavity pumps capable of handling large volumes of heavy oil combined with gas, water and sand. Initial production from these wells usually averages between 40 and 100 bbl/d of low gravity crude with gravities ranging from 11 to 18 API. Once produced, the oil is trucked or pipelined to markets in both Canada and the United States. The crude oil is then sold by Baytex and may be upgraded into lighter grades of crude or refined into petroleum products such as fuel oil, lubricants and asphalt by the crude purchasers.

In 2005, production in the Heavy Oil District averaged 21,265 bbl/d of heavy oil and 7.5 MMcf/d of natural gas (22,515 boe/d). Baytex drilled 67 (65.4 net) wells in the Heavy Oil District resulting in 59 (57.4 net) oil wells, one (1.0 net) gas well, four (4.0 net) stratigraphic test wells, and three (3.0 net) dry and abandoned wells, for a success rate of 96 percent (95 percent net).

The Heavy Oil District possesses a large inventory of development projects within the west-central Saskatchewan, Cold Lake/Ardmore, and Peace River/Seal heavy oil sands. Baytex's ability to generate relatively low-cost replacement production through conventional cold production methods is key to offsetting the Trust's overall production decline rate. Because of Baytex's large inventory of heavy oil investment projects, the Trust is able to regulate the timing and level of its capital investment program while generally maintaining production rates.

Baytex will continue to build value through internal heavy oil property development and selective acquisitions. Future heavy oil development will focus on the development of the Seal field and the newly acquired Celtic property, along with continued drilling and re-completion activity throughout Baytex's Saskatchewan properties. Company net undeveloped lands in this district totalled approximately 313,900 acres at year-end 2005.

ARDMORE: Acquired in 2002 at a production rate of 2,200 bbl/d, this property has since been extensively developed in the Sparky, McLaren and Colony formations. Average production during 2005 was approximately 4,100 bbl/d of oil and 800 Mcf/d of natural gas (4,200 boe/d). Current production is approximately 3,900 bbl/d and 700 Mcf/d of natural gas (4,000 boe/d). Sixteen successful oil wells and no dry holes were drilled in the area during 2005.

During 2006, Baytex anticipates drilling eight to ten wells. In 2005, operating expenses were maintained at $5.50/boe by using a Company-owned water disposal facility and continuing to conserve solution gas that is produced in conjunction with the heavy oil. Company net undeveloped lands were 41,800 acres at year-end 2005.

CARRUTHERS: The Carruthers property was acquired by Baytex in 1997. This property consists of separate "North" and "South" oil pools in the Cummings formation. A typical vertical oil well will initially produce at 40 bbl/d and provide an ultimate recovery of approximately 60,000 barrels of reserves. During 2005, average production was approximately 2,700 bbl/d of heavy oil and 900 Mcf/d of natural gas (2,900 boe/d). Five successful oil wells were drilled in South Carruthers during 2005. This area represents a very stable production base with continued development drilling expected to total three to five wells annually. Current production is approximately 2,900 bbl/d and 900 Mcf/d of natural gas (3,100 boe/d). Company net undeveloped lands were 12,400 acres at year-end 2005.

CELTIC: This producing property was acquired in October 2005, in a transaction which included approximately 1,750 bbl/d of SAGD production. The SAGD production was divested at the end of 2005, leaving Baytex with the cold heavy and gas production from this property. At the time of the purchase, cold production rates were approximately 1,600 bbl/d of heavy oil and 0.9 MMcf/d of natural gas. Current production has increased to over 3,000 boe/d. Celtic is a key asset for Baytex because, like the adjacent Tangleflags property, it contains a huge resource base (455 million barrels of original oil in-place) within multiple prospective horizons. The Celtic property provides a multi-year inventory of drilling locations and re-completion opportunities. Also like Tangleflags, the heavy oil is relatively gas saturated and the existing infrastructure allows for efficient capture and marketing of co-produced solution gas. In 2006, Baytex expects to drill 30 wells and recomplete 25 to 30 additional wells. In addition, it is anticipated that between 500 and 1,000 Mcf/d of solution gas sales will be added through on-going tie-in projects. Company net undeveloped lands were 7,100 acres at year-end 2005.

COLD LAKE: Located on Cold Lake First Nations lands, this heavy oil property was acquired by Baytex in 2001. Production is primarily generated from the Colony formation. Average oil production was 700 bbl/d for 2005, during which time Baytex drilled two (1.8 net) oil wells and no dry wells. Current production is approximately 670 bbl/d. Up to five new drills are anticipated during 2006. Company net undeveloped lands were 15,000 acres at year-end 2005.

MARSDEN/EPPING/MACKLIN/SILVERDALE: This area of Saskatchewan is characterized by low access costs and generally higher quality crude oils that range up to 18 API gravity. Initial production rates are typically 40 to 70 bbl/d. Primary recovery factors can be as high as 30 percent of the original oil in place because many of the oil pools in this area have a strong natural water drive. Average oil production in this area during 2005 was approximately 4,400 bbl/d. Eight oil wells were drilled in 2005 and current oil production is approximately 3,600 bbl/d. In addition, a solution gas tie-in project that currently sells 300 Mcf/d of natural gas was completed at Marsden. During 2006, a 300 Mcf/d solution gas project at Macklin is expected to be put on-stream and eight to 10 new wells are planned. Company net undeveloped lands were 19,600 acres at year-end 2005.

SEAL: Seal is a highly prospective property located in the Peace River oil sands area of northwest Alberta. Baytex holds a 100 percent working interest in approximately 100 sections of long-term oil sands leases. These oil deposits can be produced through horizontal well-bores at initial rates of approximately 150 bbl/d without resorting to more capital intensive steam injection methods. A four-well stratigraphic test program completed during the first quarter

of 2005 proved up significant extensions to our current development area located on the western block of these land holdings. Six horizontal wells drilled in late 2004 and early 2005 are currently producing approximately 500 bbl/d. The prospective undeveloped area of this westernmost block of Baytex leases comprises over 25,000 acres, and during 2006 we will drill three additional stratigraphic test wells to further delineate this acreage. In addition, two multi-lateral horizontal wells drilled with upper and lower production legs to more efficiently tap the 20 meter thick oil sand deposit will be completed and brought on-stream in 2006. Operators of adjoining lands are pursuing aggressive development programs that will contribute to vital infrastructure and allow enhanced marketing solutions for the region. As the region continues to develop, the Seal property will take an increasingly more prominent role in the Trust's development activities. Company net undeveloped lands in this area were 67,000 acres at year-end 2005.

TANGLEFLAGS: Baytex acquired the Tangleflags property in 2000. Tangleflags is characterized by multiple-zone reservoirs with production from the Colony, McLaren, Waseca, Sparky, General Petroleum and Lloydminster formations. As such, this property supplies longer-term development potential through a considerable number of uphole recompletion opportunities. Average production during 2005 was approximately 3,500 bbl/d of heavy oil and 1.4 MMcf/d of natural gas (3,700 boe/d). Current production is approximately 3,000 bbl/d and 2.1 MMcf/d. The growth in natural gas production was achieved through the conservation of solution gas produced in conjunction with the heavy oil. During 2006, Baytex plans to add three to five new wells, conduct 10 to 20 recompletions and continue tie-in of solution gas production. Company net undeveloped lands were 10,200 acres at year-end 2005.

Light Oil and Natural Gas District

Although Baytex is best known as a "heavy oil" energy trust, we also possess a growing array of light oil and natural gas properties that currently provide approximately half of our cash flow. When Baytex converted from a traditional E&P company to an energy trust in 2003, Baytex Energy Trust produced approximately 12,000 boe/d of light oil and natural gas concentrated in southeastern and northern Alberta. Over the last two and a half years, Baytex's light oil and gas production has grown to its current level of approximately 14,000 boe/d through a combination of acquisitions and development activities. Moreover, the geographic scope of our light oil and gas operations has expanded to southwest Alberta and northeast British Columbia, providing exposure to some of the most prospective areas in Western Canada.

The Light Oil and Natural Gas District produces light and medium gravity crude oil, natural gas and natural gas liquids from various fields in Alberta and British Columbia. In 2005, production averaged 52.9 MMcf/d of natural gas and 3,842 bbl/d of hydrocarbon liquids (12,662 boe/d). In 2005, the District drilled 51 (41.9 net) wells resulting in 40 (33.4 net) gas wells, five (3.0 net) oil wells, and six (5.5 net) dry and abandoned wells for a success rate of 88 percent (88 percent net). Company undeveloped lands in this district were approximately 425,600 net acres at year-end 2005.

BON ACCORD, ALBERTA: This multi-zone property was acquired by Baytex in 1997. Production, which is from the Belly River, Viking and Mannville formations, averaged approximately 6.0 MMcf/d of gas and 300 bbl/d of hydrocarbon liquids (1,300 boe/d) in 2005. Natural gas is processed at two Company-operated plants and oil is treated at three Company-operated batteries. Baytex plans to drill three wells in this area during 2006. Company net undeveloped lands were 27,400 acres at year-end 2005.

DARWIN/NINA, ALBERTA: Both properties in this winter-access area produce natural gas from the Bluesky formation. Natural gas production is processed at two Company-operated gas plants. Production during 2005 averaged approximately 4.0 MMcf/d (700 boe/d). Baytex plans to drill three wells during 2006 in the Nina/Darwin area. Company net undeveloped lands were 52,000 acres at year-end 2005.

LEAHURST, ALBERTA: Production averaged approximately 5.0 MMcf/d (800 boe/d) in 2005 from this multi-zone, year-round access area. Natural gas from the Edmonton, Belly River, Viking and Mannville formations is processed at several plants, one of which is Company-operated. In 2005, Baytex drilled 14 (11.3 net) wells for coalbed methane production from the Horseshoe Canyon Coals (three of which were also completed in the Belly River formation), and four (4.0 net) Mannville natural gas wells. In 2006, Baytex may drill up to 12 Horseshoe Canyon CBM/Belly River wells and one Mannville well in the Leahurst area. Company net undeveloped lands were 20,600 acres at year-end 2005.

RED EARTH/GOODFISH, ALBERTA: This winter-access, multi-zone property was acquired by Baytex in 1997. Relatively shallow decline oil production from Granite Wash and Slave Point pools is treated at two Company-operated sweet oil batteries. Natural gas production from the Bluesky formation is handled at two gas plants, one of which is Company-operated. Production during 2005 from this area averaged approximately 6.0 MMcf/d and 900 bbl/d of hydrocarbon liquids (1,900 boe/d). Baytex plans to drill four wells during 2006 in the Red Earth/Goodfish area. Company net undeveloped lands were 49,900 acres at year-end 2005.

RICHDALE/SEDALIA, ALBERTA: In 2001, Baytex acquired its initial position in this area and significantly increased its presence with a 2004 acquisition. During 2005, production averaged approximately 9.0 MMcf/d and 21 bbl/d of hydrocarbon liquids (1,500 boe/d). This area has advantages of year-round access and multi-zone potential (Second White Specks, Viking and Mannville). Most of the gas production is processed by two Company-operated gas plants. Baytex plans to drill three wells during 2006 in this area. Company net undeveloped lands were 60,300 acres at year-end 2005.

STODDART, BRITISH COLUMBIA: The Stoddart asset acquisition was completed in December 2004. Oil and liquids rich gas production from this largely year-round-access area comes from the Doig, Halfway, Baldonnel, Coplin and Bluesky formations. Oil is treated at two Company-operated batteries and natural gas is compressed at four Company-operated sites and sent for further processing at the outside-operated West Stoddart and Taylor Younger plants. Production during 2005 from this area averaged approximately 12.0 MMcf/d and 1,700 bbl/d of hydrocarbon liquids (3,700 boe/d). Baytex drilled nine wells in 2005 resulting in eight gas wells and one abandoned well, and plans to drill six wells and recomplete three wells in 2006. Company net undeveloped lands were 34,500 acres at December 31, 2005.

TURIN, ALBERTA: This multi-zone, year-round access property was acquired in 2004. Production during 2005 averaged approximately 2.0 MMcf/d and 700 bbl/d of hydrocarbon liquids (1,000 boe/d). Production comes from the Second White Specks, Milk River, Bow Island, Mannville, Sawtooth and Livingstone formations. Oil production is treated at three Company-operated batteries and gas is processed at two outside-operated gas plants. Baytex plans to drill three wells and recomplete five additional wells during 2006 in the Turin area. Company net undeveloped lands were 29,500 acres at December 31, 2005.

MARKETING

Crude Oil

World crude oil prices rose in 2005 as strong economic growth combined with supply disruptions and geopolitical events to continue the upward momentum from 2004. World demand for oil and products grew by 1.3 percent in 2005, a modest increase following the enormous growth of 3.8 percent in 2004. The resulting price increase demonstrated that crude oil and products supplies were not able to respond to the continued demand growth as the world's drilling and refining operations were already operating at capacity. In North America, the largest impact on crude oil supplies came from Hurricanes Katrina and Rita in August and September 2005. Much of U.S. Gulf of Mexico oil and gas producing operations were forced offline, losing approximately 110 million barrels of cumulative oil production through year-end.

The lack of excess OPEC productive capacity also contributed to record prices in 2005. After increasing production in late 2004 to meet surging Asian demand, OPEC production remained fairly flat. Geopolitical events again played a role as the ongoing conflict in Iraq, unrest in Nigeria, politics in Russia and the more-recent Iranian nuclear stand-off have left market participants very nervous.

Benchmark WTI prices began the year around US$42.00 per bbl, climbed to an all-time high of US$69.81 per bbl on August 30th, and ended the year over US$61 per bbl. The average WTI price for 2005 was US$56.56 per bbl, an increase of 37 percent from US$41.40 in 2004.

Canadian crude oil prices, while enjoying the strength in world prices, were tempered by the rising Canadian dollar against its U.S. counterpart. Canadian Par crude at Edmonton averaged $68.75 per bbl in 2005, up 31 percent from $52.57 in 2004.

With OPEC increasing production in late 2004, supplies of heavy and sour crude oil increased and prices versus benchmark light sweet prices deteriorated during 2005. Canadian heavy oil prices mirrored this trend as the differential between WTI and Lloyd blend prices in Alberta averaged US$21.82 per bbl in 2005 (39 percent of WTI) compared to US$14.01 per bbl in 2004 (34 percent of WTI).

Baytex's light oil and natural gas liquids prices averaged $53.84 per bbl before hedging in 2005 compared to $48.64 in 2004. Our heavy oil prices averaged $37.38 per bbl in 2005, compared to $30.32 in 2004.

In October 2002, Baytex signed a five-year crude oil supply agreement with Frontier Oil and Refining Company ("Frontier") of Houston, Texas. The agreement calls for Baytex to deliver 20,000 bbl/d of Lloyd Blend (LLB") quality crude at Hardisty, Alberta through the Express Pipeline to Guernsey, Wyoming. The blended crude is comprised of approximately 16,000 barrels of Baytex production and 4,000 bbl/d of diluent. Prices are fixed at 71 percent of WTI or a 29 percent LLB differential which represents the long-term average differential since 1986. This contract significantly reduces the volatility of Baytex's cash flow from its heavy oil operations.

RALPH GIBSON
VICE PRESIDENT,
MARKETING

Mr. Gibson is responsible for the transportation and marketing of Baytex's production and implementing the Trust's commodity price risk mitigation strategies.

Going forward, Baytex has entered into a series of costless collar contracts which will provide significant downside protection on the oil price while still allowing Baytex to participate in upside price potential. WTI costless collars have been put in place for 2006 on 8,000 bbl/d at a weighted average price from US$55.00 to US$84.39 per bbl and for 5,000 bbl/d for 2007 at a weighted average price from US$55.00 to US$83.69 per bbl.

Baytex is working to develop a solution to the marketing and infrastructure issues present in the Seal area and management is optimistic that solutions can be developed which will accelerate full-scale field development.

Natural Gas

Natural gas prices in North America were strong again in 2005, reflecting high oil prices, concerns over gas supplies and the severe loss of production from the hurricane activity, where 570 Bcf of production was lost during the fourth quarter. U.S. gas prices represented by the NYMEX futures contract averaged US$8.55 per Mcf in 2005, an increase of 40 percent from US $6.09 in 2004. Daily prices for Alberta gas delivered to the AECO "C" trading hub averaged $8.71 per Mcf in 2005, up 33 percent from $6.53 in 2004. Five-year averages are US$5.54 per Mcf for the NYMEX contract and $6.00 for Alberta daily prices.

Baytex received an average of $8.22 per Mcf for 2005 natural gas sales compared to $6.46 in 2004.

For 2006 Baytex has entered into several physical forward sales contracts. These agreements have locked in seasonal natural gas prices over the year at prices above the current forward strip.

PERSPECTIVE

"Marketing is the final link in the value chain. We strive to enhance the Company's revenues by minimizing transportation costs and ensuring we are selling our products to credit-worthy counterparties at fair market value. It's a dynamic and challenging environment."

OPERATIONS

Production

The Trust's average production for fiscal 2005 increased by three percent to 35,177 boe/d from 34,022 boe/d for fiscal 200.

Light oil and NGL production increased by 76 percent to 3,842 bbl/d from 2,172 bbl/d for last year. Heavy oil production for 2005 was down seven percent to 21,265 bbl/d compared to 22,703 bbl/d in 2004. Natural gas production increased by 10 percent to average 60.4 MMcf/d for 2005 compared to 54.9 MMcf/d for 2004. The reasons for the increase in production for light oil and NGL and natural gas is due to the acquisition completed in 2004 and the subsequent development of these assets. The decrease in heavy oil production is due to the reduction in drilling, where 66 net heavy oil wells were drilled in 2005 compared to 95 net wells drilled in 2004.

Production by Area	*Light Oil and NGL*	*Heavy Oil*	*Natural Gas*	*Oil Equivalent*
	(bbl/d)	*(bbl/d)*	*(MMcf/d)*	*(boe/d)*
2005				
Heavy Oil District	–	21,265	7.5	22,515
Light Oil and Natural Gas District	3,842	–	52.9	12,662
Total production	3,842	21,265	60.4	35,177
2004				
Heavy Oil District	–	22,703	8.9	24,177
Light Oil and Natural Gas District	2,172	–	46.0	9,845
Total production	2,172	22,703	54.9	34,022

Revenue

Petroleum and natural gas sales for 2005 increased by four percent to $546.9 million from $420.4 million for fiscal 2004. Benchmark WTI crude oil averaged US$56.56 per barrel for 2005, representing a 37 percent increase over the US$41.40 per barrel for 2004. However, the Trust's realized wellhead prices were reduced by a strengthening Canadian dollar, which averaged US$ 0.8253 in 2005 compared to US$ 0.7683 in 2004. The Trust's light oil and NGL price increased to $53.84 per barrel from $48.64 per barrel. The heavy oil price increased 23 percent to $37.38 per barrel in 2005 from $30.32 per barrel in 2004. Natural gas prices were 27 percent higher in 2005, averaging $8.22 per Mcf compared to $6.46 per Mcf during the previous year. Overall, after accounting for $48.5 million of realized losses on financial derivative contracts, the Trust averaged $38.82 per boe for 2005, a 41 percent increase from $27.48 per boe received in the prior year.

For 2005, light oil and NGL revenue increased 95 percent from the same period last year due to an 11 percent increase in wellhead prices and a 76 percent increase in production. Revenue from heavy oil increased 15 percent due to a 23 percent increase in wellhead prices partially offset by a 7 percent decrease in production. Revenue from natural gas increased 40 percent compared to 2004, as production increased 10 percent combined with a price increase of 27 percent.

Gross Revenue Analysis

	2005		2004	
	$ thousands	*$/Unit (1)*	*$ thousands*	*$/Unit (1)*
Oil revenue *(barrels)*				
Light oil and NGL	75,507	53.84	38,673	48.64
Heavy oil	290,163	37.38	252,016	30.32
Derivative contract loss	(48,462)	(6.24)	(78,124)	(8.58)
Total oil revenue	317,208	34.61	212,565	23.34
Natural gas revenue *(Mcf)*	181,270	8.22	129,711	6.46
Total revenue *(boe @ 6:1)*	498,478	38.82	342,276	27.48

(1) Per-unit oil revenue is in $/bbl; per unit natural gas revenue is in $/Mcf.

Royalties

For the year ended December 31, 2005, royalties increased to $81.9 million from $66.0 million for last year. Total royalties in 2005 were 15.0 percent of sales, compared to 15.7 percent of sales for 2004. For 2005, royalties were 15.1 percent of sales for light oil and NGL, 12.4 percent for heavy oil and 19.0 percent for natural gas. These rates compared to 14.1 percent, 13.3 percent and 20.9 percent, respectively, for 2004. The royalty rate for natural gas was lower in 2005 due to a retroactive adjustment in the gas cost allowance used in the calculation of royalties.

Operating Expenses

Operating expenses for 2005 increased to $110.6 million from $89.1 million in 2004. Operating expenses were $8.62 per boe for 2005 compared to $7.15 per boe for the prior year. In 2005, operating expenses were $9.06 per barrel of light oil and NGL, $9.56 per barrel of heavy oil and $1.08 per Mcf of natural gas versus $9.51, $7.83 and $0.82, respectively, for the same period a year earlier.

Transportation Expenses

Transportation expenses for 2005 were $22.4 million compared to $18.7 million for 2004. These expenses were $1.74 per boe in 2005 compared to $1.50 in 2004. Transportation expenses were $2.11 per barrel of oil and $0.14 per Mcf of natural gas in 2005, and $1.66 per barrel of oil and $0.18 per Mcf of natural gas in 2004.

Net Revenue

	Light Oil & NGL ($/bbl)		*Heavy Oil ($/bbl)*		*Total Oil & NGL ($/bbl)*		*Natural Gas ($/Mcf)*		*BOE ($/boe)*	
	2005	2004	2005	2004	2005	2004	2005	2004	2005	2004
Sales price	53.84	48.64	37.38	30.32	39.90	31.91	8.22	6.46	42.60	33.75
Royalties	(8.13)	(6.88)	(4.63)	(4.02)	(5.17)	(4.27)	(1.57)	(1.35)	(6.38)	(5.30)
Operating costs	(9.06)	(9.51)	(9.56)	(7.83)	(9.48)	(7.97)	(1.08)	(0.82)	(8.62)	(7.15)
Transportation	(1.16)	(0.92)	(2.28)	(1.73)	(2.11)	(1.66)	(0.14)	(0.18)	(1.74)	(1.50)
Net revenue	35.49	31.33	20.91	16.74	23.14	18.01	5.43	4.11	25.86	19.80

Note: Sales prices in this table are before the loss/gain recognized on financial derivative contracts.

General and Administrative Expenses

General and administrative expenses for the year were $16.0 million, compared to $15.2 million for the prior year. On a per sales unit basis, these expenses were $1.25 per boe in 2005 and $1.22 per boe in 2004. In accordance with our full cost accounting policy, no expenses were capitalized in either 2005 or 2004.

($ thousands)	2005	2004
Gross corporate expenses	**22,568**	20,413
Operator's recoveries	**(6,558)**	(5,170)
Net expenses	**16,010**	15,243

Unit Based Compensation Expense

Compensation expense related to the Trust's unit rights incentive plan was $5.3 million for 2005 compared to $4.6 million for 2004.

Compensation expense associated with rights granted under the plan is recognized in income over the vesting period of the plan with a corresponding increase or decrease in contributed surplus. The exercise of trust unit rights are recorded as an increase in trust units with a corresponding reduction in contributed surplus.

Until July 1, 2005, the Trust accounted for stock based compensation based on the intrinsic value of the awards at each reporting date. Effective July 1, 2005, on a prospective basis, the Trust began valuing options using the fair value based method. In the fourth quarter of 2005, the Trust determined that the fair value methodology should have been applied to all grants since CICA 3870 was adopted, and the financial statements of prior periods have been restated accordingly.

Interest Expense

In 2005, interest expense was $33.1 million for the year compared to $19.4 million last year. The increase in total interest expense is primarily due to the increased debt used to finance acquisitions completed in 2004, plus a gradual increase in interest rates.

Foreign Exchange

The foreign exchange gain for 2005 was $6.8 million compared to $16.0 million in the prior year. The 2005 gain is based on the translation of the U.S. dollar denominated long-term debt at 0.8577 at December 31, 2005 compared to 0.8308 at December 31, 2004. The 2004 gain is based on translation at 0.8308 at December 31, 2004 compared to 0.7737 at December 31, 2003.

Depletion, Depreciation and Accretion

Depletion, depreciation and accretion increased to $167.1 million for 2005 compared to $160.8 million for last year. On a sales-unit basis, the provision for the current year was $13.02 per boe compared to $12.91 per boe for 2004.

Income Taxes

Current tax expenses were $8.7 million for 2005 compared to $9.0 million last year. The current tax expense is comprised of $6.9 million of Saskatchewan Capital Tax and $1.8 million of Large Corporation Tax compared to $7.0 million and $2.0 million, respectively, in 2004.

The fiscal 2005 provision for future income taxes was a recovery of $7.1 million compared to a recovery of $41.2 million for the prior year. The future income tax recovery for 2004 included a non-recurring adjustment resulting from a 0.5 percent decrease to the Alberta corporate income tax rate and from the federal legislation introduced to change the taxation of resource income.

Canadian Tax Pools ($ thousands)	2005	2004
Cumulative Canadian Exploration Expense	4,953	1,283
Cumulative Canadian Development Expense	129,596	99,741
Cumulative Canadian Oil and Gas Property Expense	162,974	155,930
Undepreciated Capital Cost	179,009	195,235
Other	31,087	39,430
Total tax pools	507,619	491,619

Cash Flow from Operations

Cash flow from operations in 2005 increased 67 percent to $227.5 million from $136.0 million for the previous year. On a barrel of oil equivalent basis, cash flow from operations was $17.72 for 2005 compared to $10.03 for 2004. The increase is due to higher sales revenue and a lower realized loss from financial derivative contracts in 2005.

Cash Flow Netbacks	2005		2004	
	$/boe	*Percent*	*$/boe*	*Percent*
Production revenue	42.60	100	33.75	100
Derivative contract loss	(3.77)	(9)	(6.27)	(19)
Royalties	(6.38)	(15)	(5.30)	(16)
Operating expenses	(8.62)	(20)	(7.15)	(21)
Transportation	(1.74)	(4)	(1.50)	(4)
Operating netbacks	22.09	52	13.53	40
General and administrative expenses	(1.25)	(3)	(1.22)	(4)
Interest expense	(2.44)	(6)	(1.56)	(4)
Current taxes	(0.68)	(1)	(0.72)	(2)
Cash flow netbacks	17.72	42	10.03	30

Net Income

Net income for 2005 was $79.9 million compared to $16.8 million for 2004. The increased petroleum and natural gas sales realized through higher wellhead prices in 2005 were offset by increased operating expenses, a lower foreign exchange gain and a lower future income tax recovery. Net income for each year has also been reduced by an amount equivalent to the non-controlling interest proportionate share of the Trust's consolidated net income relating to the outstanding exchangeable shares.

Capital Expenditures

Capital expenditures during 2005 totaled $152 million, with $130 million spent on exploration and development activities and $22 million spent on acquisitions net of dispositions of assets.

For the year ended December 31, 2005, the Trust participated in the drilling of 118 (107.3 net) wells, resulting in 64 (60.4 net) oil wells, 41 (34.4 net) gas wells, four (4.0 net) stratigraphic test wells and nine (8.5 net) dry holes compared to prior year activities of 138 (135.0 net) wells, including 104 (103.1 net) oil wells, 16 (14.4 net) gas wells, seven (6.5 net) stratigraphic test wells and 11 (11.0 net) dry holes. In September 2005, Baytex purchased 3,500 boe/d of mainly heavy oil production at Celtic for $69 million. An unsolicited offer in December resulted in the sale of the SAGD production just acquired for $45.3 million. The decision to acquire these assets was based on the primary (cold) development opportunities which have been retained by Baytex. Production from the retained assets has grown to a current rate of over 3,000 boe/d from the original 1,750 boe/d at the time of acquisition. An active capital program has been planned for this area in 2006, including the drilling of 30 wells. This acquisition complements existing operations in the core area of Tangleflags and provides numerous low cost development opportunities.

	Year Ended December 31	
($ thousands)	2005	2004
Land	**7,126**	8,744
Seismic	**4,949**	1,283
Drilling and completion	**90,180**	55,322
Equipment	**23,611**	25,982
Other	**4,626**	3,152
Total exploration and development	**130,492**	94,483
Corporate acquisition	**–**	111,042
Property acquisitions	**70,986**	89,582
Property dispositions	**(49,029)**	(14,441)
Total capital expenditures	**152,449**	280,666

Liquidity and Capital Resources

At December 31, 2005, total net debt (including working capital, but excluding notional mark-to-market assets or liabilities) was $423.7 million compared to $412.5 million at December 31, 2004. The modest increase in total debt at year-end 2005 compared to 2004 is reflective of the Trust's ability to fund distributions and capital expenditures by cash flow from operations.

On June 6, 2005 the Trust issued $100 million principal amount of 6.5% convertible unsecured subordinated debentures for net proceeds of $95.8 million. The debentures pay interest semi-annually and are convertible at the option of the holder at any time into fully paid trust units at a conversion price of $14.75 per trust unit. The debentures mature on December 31, 2010 at which time they are due and payable. The net proceeds were used to reduce outstanding bank indebtedness.

The debentures have been classified as debt net of the fair value of the conversion feature which has been classified as unitholders' equity. This resulted in $95.2 million being classified as debt and $4.8 million being classified as equity as at the date of issue. Issue costs are amortized over the term of the debentures, and the debt portion will

accrete up to the principal balance at maturity. The accretion, amortization of issue costs and the interest paid are expensed as interest expense in the consolidated statements of operations. As at December 31, 2005, $22.8 million principal amount of debentures had been tendered for conversion into trust units.

The Company has a credit agreement with a syndicate of chartered banks. The credit facilities consist of an operating loan and a 364-day revolving loan. Advances under the credit facilities or letters of credit can be drawn in either Canadian or U.S. funds and bear interest at the agent bank's prime lending rate, bankers' acceptance rates plus applicable margins or LIBOR rates plus applicable margins. The facilities aggregating $250 million are subject to semi-annual review and are secured by a floating charge over all of the Company's assets. At December 31, 2005 at total of $123.6 million had been drawn under the credit facilities.

Another component of the Company's debt is the US$179.7 million of 9.625 percent senior subordinated notes due July 15, 2010. They are unsecured and are subordinate to the Company's bank credit facilities. The Company entered into an interest rate swap contract converting the fixed rate to a floating rate reset quarterly at the three month LIBOR rate plus 5.2 percent until the maturity of these notes.

Pursuant to various agreements with Baytex's creditors, we are restricted from making distributions to unitholders where the distribution would or could have a material adverse effect on the Trust's or its subsidiaries' ability to fulfill its obligations under Baytex's credit facilities.

The Trust believes that cash flow generated from its operations, together with existing capacity under the bank facilities, will be sufficient to finance current operations and planned capital expenditures for the next year. The timing of most of the capital expenditures is discretionary and there are no material long-term capital expenditure commitments.

UNITHOLDERS' EQUITY

The Trust is authorized to issue an unlimited number of trust units.

On October 18, 2004, the Trust implemented a Distribution Reinvestment Plan ("DRIP"). Under the DRIP, Canadian unitholders are entitled to reinvest monthly cash distributions in additional trust units of the Trust. At the discretion of the Trust, these additional units will be issued from treasury at 95 percent of the "weighted average closing price", or acquired on the market at prevailing market rates. For the purposes of the units issued for treasury, the "weighted average closing price" is calculated as the weighted average trading price of trust units for the period commencing on the second business day after the distribution record date and ending on the second business day immediately prior to the distribution payment date, such period not to exceed 20 trading days. The Trust can also acquire trust units to be issued under the DRIP at prevailing market rates.

On December 20, 2004, the Trust issued 3,600,000 trust units at $12.80 per unit for gross proceeds of $46.1 million pursuant to a prospectus.

Non-controlling Interest

The Company is authorized to issue an unlimited number of exchangeable shares. The exchangeable shares can be converted (at the option of the holder) into trust units at any time up to September 2, 2013. Up to 1.9 million exchangeable shares may be redeemed annually by the Company for either cash or the issue of trust units. At December 31, 2005, there were 1.6 million exchangeable shares outstanding. During 2005, a total of 0.3 million

exchangeable shares were exchanged for trust units. The number of trust units issuable upon conversion is based upon the exchange ratio in effect at the conversion date. The exchange ratio is calculated monthly based on the cash distribution paid divided by the weighted average trust unit price of the five-day trading period ending on the record date. The exchange ratio at December 31, 2005 was 1.37201 trust units per exchangeable share (December 31, 2004 – 1.21472 trust units per exchangeable share). Cash distributions are not paid on the exchangeable shares. The exchangeable shares are not publicly traded, although they may be transferred by the holder without first being converted to trust units.

The exchangeable shares of the Company are presented as a non-controlling interest on the consolidated balance sheet because they fail to meet the non-transferability criteria necessary for them to be classified as equity. Net income has been reduced by an amount equivalent to the non-controlling interest proportionate share of the Trust's consolidated net income with a corresponding increase to the non-controlling interest on the balance sheet.

Cash Distributions

During 2005 total cash distributions of $1.80 per unit were declared. The monthly cash distribution of $0.15 per unit has been maintained since the inception of the Trust in September 2003 and was increased to $0.18 per unit in 2006.

Off Balance Sheet Arrangements and Contractual Obligations

The Trust has assumed various contractual obligations and commitments, as detailed in the table below, in the normal course of operations and financing activities. These obligations and commitments have been considered when assessing the cash requirements in the above discussion of future liquidity.

Contractual Obligations at December 31, 2005

($ thousands)		*Payments Due*		
	Total	*Within 1 year*	*1–3 years*	*4–5 years*
Operating leases	8,117	1,621	5,834	662
Transportation agreements	3,446	2,052	1,394	–
Total obligations	11,563	3,673	7,228	662

The Trust also has ongoing obligations related to the abandonment and reclamation of well and facility sites which have reached the end of their economic lives. Programs to abandon and reclaim well and facility sites are undertaken regularly in accordance with applicable legislative requirements.

Risk and Risk Management

The exploration for and the development, production and marketing of petroleum and natural gas involves a wide range of business and financial risks, some of which are beyond the Trust's control. Included in these risks are the uncertainty of finding new reserves, the fluctuations of commodity prices, the volatile nature of interest and foreign exchange rates, and the possibility of changes to royalty, tax and environmental regulations. The petroleum industry is highly competitive and the Trust competes with a number of other entities, many of which have greater financial and operating resources.

The business risks facing the Trust are mitigated in a number of ways. Geological, geophysical, engineering, environmental and financial analyses are performed on new exploration prospects, development projects and potential acquisitions to ensure a balance between risk and reward. The Trust's ability to increase its production, revenues and cash flow depends on its success in not only developing its existing properties but also in acquiring, exploring for and developing new reserves and production and managing those assets in an efficient manner.

Despite best practice analysis being conducted on all projects, there are numerous uncertainties inherent in estimating quantities of petroleum and natural gas reserves, including future oil and natural gas prices, engineering data, projected future rates of production and the timing of future expenditures. The process of estimating petroleum and natural gas reserves requires substantial judgment, resulting in imprecise determinations, particularly for new discoveries. An independent engineering firm evaluates the Trust's properties annually to determine a fair estimate of reserves. The Reserves Committee, consisting of qualified members of the Company's Board of Directors, assists the Board in their annual review of the reserve estimates.

The provision for depletion and depreciation in the financial statements and the ceiling test are based on proved reserve estimates. Any future significant revisions could result in a full cost accounting write-down or material changes to the annual rate of depletion and depreciation.

The financial risks that the Trust is exposed to as part of the normal course of its business are managed, in part, with various financial derivative instruments, in addition to fixed-price physical delivery contracts. The use of derivative instruments is governed under formal internal policies and subject to limits established by the Board of Directors. Derivative instruments are not used for speculative or trading purposes.

The Trust's financial results can be significantly affected by the prices received for petroleum and natural gas production as commodity prices fluctuate in response to changing market forces. This pricing volatility is expected to continue. As a result, The Trust has a risk management program that may be used to protect the prices of oil and natural gas on a portion of the total expected production. The objective is to decrease exposure to market volatility and ensure the Trust's ability to finance its distributions and capital program.

The Trust's financial results are also impacted by fluctuations in the exchange rate between the Canadian dollar and the US dollar. Crude oil and, to a large extent, natural gas prices are based on reference prices denominated in US dollars, while the majority of expenses are denominated in Canadian dollars. The exchange rate also impacts the valuation of the US dollar denominated long-term notes. The related foreign exchange gains and losses are included in net income. There is no plan at this time to fix the exchange rate on any of the Trust's long-term borrowings.

The Trust is exposed to changes in interest rates as the Company's banking facilities are based on our lenders' prime lending rate and short-term Bankers' Acceptance rates. Changes in interest rates also impact the Company's interest rate swap contract which converts the fixed interest rate of 9.625 percent on the US$179.7 million notes to a floating rate reset quarterly at the three month LIBOR rate plus 5.2 percent until the maturity of these notes.

The Trust's current position with respect to its financial derivative contracts is detailed in note 17 of the consolidated financial statements.

A summary of certain risk factors relating to our business is included in our Annual Information Form under the Risk Factors section.

CRITICAL ACCOUNTING POLICIES

The preparation of the consolidated financial statements in accordance with generally accepted accounting principles requires management to make judgments and estimates that affect the financial results of the Trust. These critical estimates are discussed below.

Oil and Gas Accounting

The Trust follows the full-cost accounting guideline to account for its petroleum and natural gas operations. Under this method, all costs associated with the exploration for and development of petroleum and natural gas reserves are capitalized in one Canadian cost centre. These capitalized costs, along with estimated future development costs, are depleted and depreciated on a unit-of-production basis using estimated proved petroleum and natural gas reserves. By their inclusion in the unit-of-production calculation, reserves estimates are a significant component of the calculation of depletion and depreciation and site restoration expense.

Independent engineers engaged by the Trust use all available geological, reservoir, and production performance data to prepare the reserves estimates. These estimates are reviewed and revised, either upward or downward, as new information becomes available. Revisions are necessary due to changes in assumptions based on reservoir performance, prices, economic conditions, government restrictions and other relevant factors. If reserves estimates are revised downward, net income could be affected by increased depletion and depreciation.

Impairment of Petroleum and Natural Gas Assets

Companies that use the full-cost method of accounting for oil and natural gas operations are required to perform a ceiling test each quarter that calculates a limit for the net carrying cost of petroleum and natural gas assets. The net amount at which petroleum and natural gas properties are carried is subject to a cost recovery test (the "ceiling test"). The ceiling test is a two-stage process which is to be performed at least annually. The first stage of the test is a recovery test which compares the undiscounted future cash flow from proved reserves at forecast prices plus the cost less impairment of unproved properties to the net book value of the petroleum and natural gas assets to determine if the assets are impaired. An impairment loss exists when the net book value of the petroleum and natural gas assets exceeds such undiscounted cash flow. The second stage determines the amount of the impairment loss to be recorded. The impairment is measured as the amount by which the net book value of the petroleum and natural gas assets exceeds the future discounted cash flow from proved plus probable reserves at forecast prices. If reserve estimates are revised downward, net income could be affected by any additional depletion and deprecation recorded under the ceiling test calculation and could result a significant accounting loss for a particular period.

Asset Retirement Obligations

The amounts recorded for asset retirement obligations were estimated based on the Trust's net ownership interest in all wells and facilities, estimated costs to abandon and reclaim the wells and the facilities and the estimated time period during which these costs will be incurred in the future. Any changes to these estimates could change the amount recorded for asset retirement obligations and may materially impact the consolidated financial statements of future periods.

CHANGE IN ACCOUNTING POLICY

Unit-Based Compensation

Until July 1, 2005, the Trust accounted for stock based compensation based on the intrinsic value of the awards at each reporting date. Effective July 1, 2005, on a prospective basis, the Trust began valuing options using the fair value based method. In the fourth quarter of 2005, the Trust determined that the fair value methodology should have been applied to all grants since CICA 3870 was adopted, and the financial statements of prior periods have been restated accordingly.

As a result of retroactively adopting the fair value method of estimating compensation expense, net income for the comparative year ended December 31, 2004 was increased by $3.0 million, net of non-controlling interest of $0.09 million. The opening 2004 accumulated deficit was increased by $1.7 million, net of non-controlling interest of $0.1 million. There was also a decrease in unitholders' capital of $0.07 million during 2004 relating to the transfer of value from contributed surplus on exercise of unit option rights. There was no impact on cash flow as a result of adopting this policy.

NEW ACCOUNTING PRONOUNCEMENTS

Financial Instruments

In January 2005 the CICA issued three new standards relating to the reporting of financial instruments in financial statements. These standards introduce new requirements for the recognition and measurement of financial instruments and comprehensive income. Section 3855, "Financial Instruments – Recognition and Measurement" requires that all financial instruments, including derivatives, are to be included on a company's balance sheet and measured, either at their fair values or, in limited circumstances when fair value may not be considered most relevant, at cost or amortized cost. The standard also provides guidance on when gains and losses as a result of changes in fair values are to be recognized in the income statement.

The issuance of the new Section 3855 will result in amendments to Section 3860 "Financial Instruments – Disclosure and Presentation" to make the scope and definitions consistent with that of the new Section 3855, including expanding the scope to include certain commodity-based contracts, and to update certain disclosures in light of the introduction of Section 3855. Other Handbook Sections have also been amended for conformity with the new standards.

Section 3865 "Hedges", extends the existing requirements for hedge accounting currently under AcG-13. This new section allows for the optional treatment of accounting for financial instruments that are designated as either fair value hedges, cash flow hedges or hedges of a net investment in a self-sustaining foreign operation. For a fair value hedge, the gain or loss on a derivative hedging item, or the gain or loss on a non-derivative hedging item attributable to the hedged risk, is recognized in net income in the period of change together with the offsetting loss or gain on the hedged item attributable to the hedged risk. The carrying amount of the hedged item is adjusted for the hedged risk. For a cash flow hedge, the effective portion of the hedging item's gain or loss is initially reported in other comprehensive income and subsequently reclassified to net income when the hedged item affects net income. For a hedge of a net investment in a self-sustaining foreign operation the same accounting is followed as for a cash flow hedge.

A new location for recognizing certain gains and losses – other comprehensive income – has been introduced with the issued of Section 1530, "Comprehensive Income". An integral part of the accounting standards on recognition and measurement of financial instruments is the ability to present certain gains and losses outside net income, in other Comprehensive Income. This standard requires that a company should present comprehensive income and its components in a financial statement displayed with the same prominence as other financial statements that constitute a complete set of financial statements, in both annual and interim financial statements. Exchange gains and losses arising from the translation of the financial statements of a self-sustaining foreign operation, previously recognized in a separate component of shareholders' equity, in accordance with Section 1650, "Foreign Currency Translation", will now be recognized in a separate component of other comprehensive income.

These three new Handbook Sections are effective date for annual and interim periods in fiscal years beginning on or after October 1, 2006. The Trust is evaluating the impact the adoption of these new standards will have on its consolidated financial statements.

Non-Monetary Transactions

In June 2005, The CICA issued Section 3831 "Non-Monetary Transactions", which replaces the culmination of earnings test with a commercial substance test as the criteria for fair value measurement. In addition, fair value measurement is clarified. The Trust does not expect application of this new standard to have a material impact on its consolidated financial statements.

FOURTH QUARTER 2004

The following discussion reviews the Trust's results of operations for the fourth quarter of 2004.

Light oil and NGL production for the fourth quarter of 2005 increased by 44 percent to 4,022 bbl/d from 2,786 bbl/d a year earlier. Heavy oil production increased seven percent to 24,051 bbl/d for the fourth quarter of 2005 compared to 22,490 bbl/d a year ago. Natural gas production increased by six percent to 58.9 MMcf/d for the fourth quarter of 2005 compared to 55.5 MMcf/d for the same period last year. The increase in light oil and NGL and natural gas production is due to the acquisitions completed in 2004 and the subsequent development of these assets. The increase in heavy oil production is attributable to the Celtic acquisition made during the year.

Petroleum and natural gas sales increased 46 percent to $162.4 million for the fourth quarter of 2005 from $111.5 million for the same period in 2004. Revenue from light oil and NGL for the fourth quarter of 2005 increased 60 percent from the same period a year ago due to a 44 percent increase in production and a 11 percent increase in wellhead prices. Revenue from heavy oil increased 29 percent due to a seven percent increase in production and a 21 percent increase in wellhead prices. Revenue from natural gas increased 72 percent as the result of a 62 percent increase in wellhead prices and a six percent increase in production.

Total royalties increased to $27.3 million for the fourth quarter of 2005 from $17.4 million in 2004. This increase is reflective of the increase in total revenue. Total royalties for the fourth quarter of 2005 were 16.8 percent of sales compared to 15.6 percent of sales for the same period in 2004. For the fourth quarter of 2005, royalties were 16.2 percent of sales for light oil and NGL, 11.7 percent for heavy oil and 24.3 percent for natural gas. These rates compared to 15.9 percent, 13.5 percent and 19.5 percent, respectively, for the same period last year.

Operating expenses for the fourth quarter of 2005 increased to $33.3 million from $24.3 million in the corresponding quarter last year. Operating expenses were $9.55 per boe for the fourth quarter of 2005 compared to $7.63 per boe for the fourth quarter of 2004. The increase in operating expenses per boe was primarily due to an inflationary cost environment for fuel and oilfield services, and the addition of heavy oil production utilizing SAGD technology which was disposed of at year-end 2005. For the fourth quarter of 2005, operating expenses were $6.28 per barrel of light oil and NGL, $11.00 per barrel of heavy oil and $1.22 per Mcf of natural gas. The operating expenses for the same period a year ago were $8.57, $8.61 and $0.83, respectively.

Transportation expenses for the fourth quarter of 2005 were $6.0 million compared to $4.6 million for the fourth quarter of 2004. These expenses were $1.71 per boe for the fourth quarter of 2005 compared to $1.43 for the same period in 2004. Transportation expenses were $2.02 per barrel of oil and $0.14 per Mcf of natural gas. The corresponding amounts for 2004 were $1.58 and $0.17, respectively.

General and administrative expenses for the fourth quarter of 2005 increased slightly to $4.6 million from $4.1 million in 2004. On a per sales unit basis, these expenses were $1.32 per boe for the fourth quarter of 2005 compared to $1.28 per boe for the same period in 2004. In accordance with our full cost accounting policy, no general and administrative expenses were capitalized in either the fourth quarter of 2005 or 2004.

Compensation expense related to the Trust's unit rights incentive plan was $1.8 million for the fourth quarter of 2005 compared to $1.0 million for the fourth quarter of 2004.

Interest expense increased to $9.7 million for the fourth quarter of 2005 from $6.4 million for the same quarter last year, primarily due to the increased debt used to finance acquisitions, plus a gradual increase in interest rates.

Foreign exchange in the fourth quarter of 2005 was a loss of $0.9 million compared to a gain of $10.9 million in the prior year. The loss is based on the translation of the US dollar denominated long-term debt at 0.8577 at December 31, 2005 compared to 0.8613 at September 30, 2005. The 2004 gain is based on translation at 0.8308 at December 31, 2004 compared to 0.7912 at September 30, 2004.

The provision for depletion, depreciation and accretion at $41.6 million for the fourth quarter of 2005 is almost unchanged from the same quarter a year ago despite higher production, due to a lower depletion rate resulting from low-cost proved reserves added from the Celtic acquisition. On a sales-unit basis, the provision for the current quarter was $11.91 per boe compared to $13.04 per boe for the same quarter in 2004.

Net income for the fourth quarter of 2005 was $35.2 million compared to $42.7 million for the fourth quarter in 2004. The variance was the result of higher production and higher sales prices, offset by foreign exchange losses and an increase in future tax provision.

Trust Unit Information

At February 28, 2006, the Trust had 71,231,684 units outstanding and the Company had 1,594,733 exchangeable shares outstanding. The exchange ratio at February 28, 2006 was 1.39624 trust units per exchangeable share.

At February 28, 2006, the Trust had $55.0 million convertible unsecured subordinated debentures outstanding which are convertible at the option of the holder at any time into fully paid trust units at a conversion price of $14.75 per unit.

SELECTED ANNUAL INFORMATION

Financial *($ thousands, except per unit amounts)*	2005	2004 (3)	2003 (2)(3)
Revenue	546,940	420,400	403,022
Net income (1)	79,876	16,764	34,141
Per unit basic (1)	1.19	0.27	0.64
Per unit diluted (1)	1.15	0.26	0.59
Total assets	1,105,567	1,104,136	982,640
Total long-term financial liabilities	283,565	216,583	232,562
Cash distributions declared per unit	1.80	1.80	0.60

(1) Net income and net income per unit is after non-controlling interest related to exchangeable shares. The net income and net income per unit for 2003 have been restated due to the retroactive application of the new accounting standard for non-controlling interest (see note 3 of the consolidated financial statements). The application of this standard did not impact the 2002 financial information.

(2) The financial information for 2003 has been restated for the adoption of the new accounting standards related to asset retirement obligations and transportation expenses.

(3) The financial information for 2004 and 2003 has been restated for the adoption of fair value based method of calculating unit-based compensation expense.

Overall production for 2005 was 35,177 boe per day which represented a three percent increase from 34,022 boe per day in 2004. Average wellhead prices received during 2005 were $42.60 per boe compared to $33.75 during 2004. Production in 2003 was 36,686 boe per day. Average wellhead prices received in 2003 were $28.07 per boe.

QUARTERLY INFORMATION

Financial *(unaudited)*	2005				2004 (2)			
($ thousands, except per share amounts)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Revenue	162,356	154,930	118,379	111,275	111,521	108,216	104,517	96,146
Cash flow from operations	65,487	67,501	49,937	44,540	28,144	32,235	36,944	38,689
Per unit basic	0.95	1.00	0.75	0.67	0.44	0.50	0.57	0.60
Per unit diluted	0.86	0.90	0.71	0.64	0.42	0.49	0.57	0.60
Cash distributions declared per unit	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45
Net income (loss) (1)	35,184	39,524	16,779	(11,611)	42,696	(10,672)	(10,585)	(4,674)
Per unit basic (1)	0.51	0.59	0.25	(0.17)	0.67	(0.17)	(0.17)	(0.08)
Per unit diluted (1)	0.48	0.55	0.25	(0.17)	0.66	(0.17)	(0.17)	(0.07)

(1) Net income and net income per unit is after non-controlling interest related to exchangeable shares. The net income and net income per unit for 2003 have been restated due to the retroactive application of the new accounting standard for non-controlling interest (see note 3 of the consolidated financial statements).

(2) The financial information for 2004 and 2003 has been restated for the adoption of fair value based method of calculating unit-based compensation expense.

Production	2005				2004			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Light oil and NGL *(bbl/d)*	4,022	4,063	3,404	3,876	2,786	1,890	1,952	2,058
Heavy oil *(bbl/d)*	24,051	20,061	19,653	21,279	22,490	22,083	22,927	23,322
Total oil and NGL *(bbl/d)*	28,073	24,124	23,058	25,155	25,276	23,974	24,879	25,380
Natural gas *(MMcf/d)*	58.9	63.9	59.3	59.5	55.5	50.9	57.2	56.0
Oil equivalent *(boe/d @ 6:1)*	37,895	34,780	32,937	35,068	34,525	32,454	34,411	34,709
Average Prices								
WTI oil *(US$/bbl)*	60.02	63.19	53.17	49.84	48.28	43.88	38.32	35.15
Edmonton par oil *($/bbl)*	71.18	76.51	65.76	61.44	57.72	56.32	50.59	45.59
BTE light oil *($/bbl)*	55.78	59.24	53.06	46.69	50.46	52.63	47.55	43.50
BTE heavy oil *($/bbl)*	37.75	45.39	35.71	30.83	31.24	34.69	29.21	26.29
BTE total oil *($/bbl)*	40.33	47.74	28.27	33.27	33.35	36.11	30.63	27.70
BTE natural gas *($/Mcf)*	10.69	8.39	7.08	6.69	6.60	6.16	6.61	6.43
BTE oil equivalent *($/boe)*	46.48	48.54	39.53	35.21	35.03	36.34	33.12	30.63

2006 GUIDANCE

Baytex has set a $105 million exploration and development capital budget for 2006, with approximately $65 million allocated for activities relating to heavy oil and $40 million for activities relating to natural gas and light oil. Production for the year is targeted to average 35,000 boe/d, with heavy oil at 21,000 bbl/d, natural gas at 61.2 MMcf/d and light oil and NGL at 3,800 bbl/d.

Baytex has entered into the following contracts to provide downside protection to 2006 and 2007 cash flow while allowing for participation in a high commodity price environment. Baytex will continue to monitor market developments and may enter into additional similar contracts if deemed desirable.

Financial Derivative Contracts

At December 31, 2005, the Trust had derivative contracts for the following:

OIL

	Period	*Volume*	*Price*	*Index*
Price collar	Calendar 2006	2,000 bbl/d	US$55.00 – $80.85	WTI
Price collar	Calendar 2006	2,000 bbl/d	US$55.00 – $84.18	WTI
Price collar	Calendar 2006	2,000 bbl/d	US$55.00 – $85.30	WTI
Price collar	Calendar 2006	1,000 bbl/d	US$55.00 – $87.10	WTI
Price collar	Calendar 2006	1,000 bbl/d	US$55.00 – $87.35	WTI

FOREIGN CURRENCY

	Period	*Amount*	*Floor*	*Cap*
Collar	Calendar 2006	US$3,000,000 per month	CAD/US$1.1700	CAD/US$1.2065

INTEREST RATE SWAP

	Period	*Principal*	*Rate*
	November 2003 to July 2010	US$179,699,000	3-month LIBOR plus 5.2%

In 2006, the Company entered into derivative contracts for the following:

OIL

	Period	*Volume*	*Price*	*Index*
Price collar	Calendar 2007	2,000 bbl/d	US$55.00 – $83.60	WTI
Price collar	Calendar 2007	3,000 bbl/d	US$55.00 – $83.75	WTI

FOREIGN CURRENCY

	Period	*Amount*	*Floor*	*Cap*
Collar	February 1, 2006 to December 31, 2006	US$4,000,000 per month	CAD/US$1.1500	CAD/US$1.1835
Collar	January 9, 2006 to December 31, 2006	US$3,000,000 per month	CAD/US$1.1500	CAD/US$1.1780

Physical Sale Contracts

GAS

	Period	*Volume*	*Price*
Fixed price	January 1, 2006 to February 28, 2006	3,000 GJ/d	CAD$10.00
Fixed price	January 1, 2006 to March 31, 2006	5,000 GJ/d	CAD$10.07
Fixed price	January 1, 2006 to March 31, 2006	5,000 GJ/d	CAD$10.20
Fixed price	January 1, 2006 to March 31, 2006	2,000 GJ/d	CAD$10.63
Fixed price	March 1, 2006 to March 31, 2006	3,000 GJ/d	CAD$11.53
Fixed price	April 1, 2006 to October 31, 2006	5,000 GJ/d	CAD$8.40
Fixed price	April 1, 2006 to October 31, 2006	2,000 GJ/d	CAD$9.01
Price collar	January 1, 2006 to October 31, 2006	5,000 GJ/d	CAD$7.50 – $13.40
Price collar	April 1, 2006 to October 31, 2006	2,000 GJ/d	CAD$7.80 – $10.55
Price collar	April 1, 2006 to October 31, 2006	3,000 GJ/d	CAD$9.50 – $12.60

The Trust is exposed to credit-related losses in the event of non-performance by counter-parties to these contracts. See note 17 to the December 31, 2005 consolidated financial statements for description of accounting treatment of these derivative contracts.

Evaluation of Disclosure Controls and Procedures

Raymond Chan, the President and Chief Executive Officer, and Derek Aylesworth, the Chief Financial Officer of Baytex (together the "Disclosure Officers"), are responsible for establishing and maintaining disclosure controls and procedures for Baytex. For the year ended December 31, 2005, the Disclosure Officers evaluated the effectiveness of the disclosure controls and procedures. As a result of this evaluation, the Disclosure Officers have concluded that the disclosure controls and procedures are effective to provide reasonable assurance that all material or potentially material information about the activities of the Trust is made known to them by others within Baytex.

It should be noted that while our President and Chief Executive Officer and Chief Financial Officer believe that Baytex's disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the disclosure controls and procedures or internal controls over financial reporting will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

ADDITIONAL INFORMATION

Additional information relating to the Trust, including the Annual Information Form, may be found on SEDAR at www.sedar.com.

Management, in accordance with Canadian generally accepted accounting principles, has prepared the accompanying consolidated financial statements of Baytex Energy Trust. Financial and operating information presented throughout this Annual Report is consistent with that shown in the consolidated financial statements.

Management is responsible for the integrity of the financial information. Internal control systems are designed and maintained to provide reasonable assurance that assets are safeguarded from loss or unauthorized use and to produce reliable accounting records for financial reporting purposes.

Deloitte & Touche LLP were appointed by the Trust's unitholders to express an opinion on the consolidated financial statements. Their examination included such tests and procedures, as they considered necessary, to provide a reasonable assurance that the consolidated financial statements are presented fairly in accordance with Canadian generally accepted accounting principles.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board exercises this responsibility through the Audit Committee, with assistance from the Reserves Committee regarding the annual review of our petroleum and natural gas reserves. The Audit Committee meets regularly with management and the independent auditors to ensure that management's responsibilities are properly discharged, to review the consolidated financial statements and recommend that the consolidated financial statements be presented to the Board of Directors for approval. The Audit Committee also considers the independence of the external auditors and reviews their fees. The external auditors have access to the Audit Committee without the presence of management.

Raymond T. Chan, CA
President and Chief Executive Officer
Baytex Energy Ltd.

W. Derek Aylesworth, CA
Chief Financial Officer
Baytex Energy Ltd.

March 7, 2006

AUDITORS' REPORT

To the Unitholders of Baytex Energy Trust

We have audited the consolidated balance sheets of Baytex Energy Trust (the "Trust") as at December 31, 2005 and 2004 and the consolidated statements of operations and accumulated income (deficit) and cash flows for the years then ended. These financial statements are the responsibility of the management of the Trust. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the accounting principles used and significant estimates made by management, as well as evaluating the overall consolidated financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2005 and 2004 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

On March 7, 2006, we reported separately to the Trustee and Unitholders of Baytex Energy Trust on the consolidated financial statements for the same period, prepared in accordance with Canadian generally accepted accounting principles but which included Note 19, Differences between Canadian and United States Generally Accepted Accounting Principles.

Deloitte & Touche LLP

Calgary, Alberta

March 7, 2006

Deloitte & Touche LLP

Chartered Accountants

CONSOLIDATED BALANCE SHEETS

As at December 31, 2005 and 2004 (thousands)	2005	2004 *(restated – note 3)*
ASSETS		
Current assets		
Accounts receivable	$ 73,869	$ 41,154
Crude oil inventory	9,984	7,299
Financial derivative contracts *(note 17)*	5,183	–
	89,036	48,453
Deferred charges and other assets	9,038	6,491
Petroleum and natural gas properties *(note 5)*	969,738	1,009,933
Goodwill *(note 4)*	37,755	39,259
	$ 1,105,567	$ 1,104,136
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities	$ 89,966	$ 72,976
Distributions payable to unitholders	10,393	9,981
Bank loan *(note 6)*	123,588	161,444
Financial derivative contracts *(note 17)*	–	9,513
	223,947	253,914
Long-term debt *(note 7)*	209,799	216,583
Convertible debentures *(note 8)*	73,766	–
Asset retirement obligation *(note 9)*	33,010	73,297
Deferred obligations *(note 18)*	4,558	–
Future income taxes *(note 14)*	159,745	164,909
	704,825	708,703
Non-controlling interest *(note 11)*	12,810	12,936
UNITHOLDERS' EQUITY		
Unitholders' capital *(note 10)*	555,020	515,663
Conversion feature of debentures *(note 8)*	3,698	–
Contributed surplus	10,332	6,287
Accumulated distributions	(267,986)	(146,445)
Accumulated income	86,868	6,992
	387,932	382,497
	$ 1,105,567	$ 1,104,136

Commitments and contingencies *(note 18)*

See accompanying notes to the consolidated financial statements.

On behalf of the Board

Naveen Dargan
Director, Baytex Energy Ltd.

Blake Cassidy
Director, Baytex Energy Ltd.

CONSOLIDATED STATEMENTS OF OPERATIONS AND ACCUMULATED INCOME (DEFICIT)

Years ended December 31, 2005 and 2004 (thousands, except per unit data)	2005	2004 *(restated – note 3)*
Revenue		
Petroleum and natural gas sales	$ 546,940	$ 420,400
Royalties	(81,898)	(65,988)
Realized loss on financial derivatives	(48,462)	(78,124)
Unrealized gain on financial derivatives	14,696	597
	431,276	276,885
Expenses		
Operating	110,648	89,078
Transportation	22,399	18,714
General and administrative	16,010	15,243
Unit based compensation *(note 12)*	5,346	4,646
Interest *(note 7)*	33,124	19,412
Foreign exchange gain *(note 7)*	(6,784)	(15,979)
Depletion, depreciation and accretion	167,135	160,808
	347,878	291,922
Income (loss) before income taxes and non-controlling interest	83,398	(15,037)
Income taxes (recovery) *(note 14)*		
Current	8,747	9,000
Future	(7,074)	(41,237)
	1,673	(32,237)
Income before non-controlling interest	81,725	17,200
Non-controlling interest *(note 11)*	(1,849)	(436)
Net income	79,876	16,764
Accumulated income (deficit), beginning of year, as previously reported	5,694	(8,069)
Accounting policy change for Unit based compensation *(note 3)*	1,298	(1,703)
Accumulated income (deficit) beginning of year, as restated	6,992	(9,772)
Accumulated income, end of year	$ 86,868	$ 6,992
Net income per trust unit *(note 13)*		
Basic	$ 1.19	$ 0.27
Diluted	$ 1.15	$ 0.26

See accompanying notes to the consolidated financial statements.

Years ended December 31, 2005 and 2004 (thousands)	2005	2004 *(restated – note 3)*
CASH PROVIDED BY (USED IN):		
Operating activities		
Net income	$ 79,876	$ 16,764
Items not affecting cash:		
Unit based compensation *(note 12)*	5,346	4,646
Amortization of deferred charges	1,492	11,171
Unrealized foreign exchange gain	(6,784)	(15,979)
Depletion, depreciation and accretion	167,135	160,808
Accretion on debentures *(note 8)*	321	–
Unrealized gain on financial derivatives *(note 17)*	(14,696)	(597)
Future income taxes (recovery)	(7,074)	(41,237)
Non-controlling interest *(note 11)*	1,849	436
	227,465	136,012
Change in non-cash working capital *(note 15)*	(20,212)	3,589
Asset retirement expenditures	(1,637)	(2,739)
Decrease in deferred charges and other assets	(977)	212
	204,639	137,074
Financing activities		
Issuance of convertible debentures *(note 8)*	100,000	–
Convertible debentures issue costs *(note 8)*	(4,250)	–
Increase (decrease) in bank loan	(37,856)	161,444
Issue of trust units *(note 10)*	2,916	44,505
Payments of distributions	(114,221)	(112,074)
	(53,411)	93,875
Investing activities		
Petroleum and natural gas property expenditures	(201,478)	(184,065)
Corporate acquisition *(note 4)*	–	(111,042)
Proceeds on disposal of petroleum and natural gas properties	49,029	14,441
Change in non-cash working capital *(note 15)*	1,221	(4,014)
	(151,228)	(284,680)
Change in cash and short-term investments during the year	–	(53,731)
Cash and short-term investments, beginning of year	–	53,731
Cash and short-term investments, end of year	$ –	$ –

See accompanying notes to the consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Years ended December 31, 2005 and 2004
(all tabular amounts in thousands, except per unit amounts)

1. BASIS OF PRESENTATION

Baytex Energy Trust (the "Trust") was established on September 2, 2003 under a Plan of Arrangement. The Trust is an open-ended investment trust created pursuant to a trust indenture. Subsequent to the Plan of Arrangement, Baytex Energy Ltd. (the "Company") is a subsidiary of the Trust.

The consolidated financial statements include the accounts of the Trust and its subsidiaries and have been prepared by management in accordance with Canadian generally accepted accounting principles as described in note 2.

2. SIGNIFICANT ACCOUNTING POLICIES

Consolidation

The consolidated financial statements include the accounts of the Trust and its wholly owned subsidiaries from the respective dates of acquisition of the subsidiary companies. Inter-company transactions and balances are eliminated upon consolidation.

Measurement Uncertainty

The preparation of the consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and revenues and expenses during the reporting period. Actual results can differ from those estimates.

In particular, amounts recorded for depreciation and depletion and amounts used for ceiling test calculations are based on estimates of petroleum and natural gas reserves and future costs required to develop those reserves. The Trust's reserve estimates are evaluated annually by an independent engineering firm. By their nature, these estimates of reserves and the related future cash flows are subject to measurement uncertainty, and the impact on the consolidated financial statements of future periods could be material.

The amounts recorded for asset retirement obligations were estimated based on the Trust's net ownership interest in all wells and facilities, estimated costs to abandon and reclaim the wells and the facilities and the estimated time period during which these costs will be incurred in the future. Any changes to these estimates could change the amount recorded for asset retirement obligations and may materially impact the consolidated financial statements of future periods.

Cash and Short-term Investments

Cash and short-term investments include monies on deposit and short-term investments, accounted for at cost, which have an initial maturity date of not more that 90 days.

Crude Oil Inventory

Crude oil inventory, consisting of production in transit in pipelines at the balance sheet date pursuant to a long-term crude oil supply agreement, is valued at the lower of cost or net realizable value.

Petroleum and Natural Gas Operations

The Trust follows the full cost method of accounting for its petroleum and natural gas operations whereby all costs relating to the exploration for and development of petroleum and natural gas reserves are capitalized in one Canadian cost centre and charged against income, as set out below. Such costs include land acquisition, drilling of productive and non-productive wells, geological and geophysical, production facilities, carrying costs directly related to unproved properties and corporate expenses directly related to acquisition, exploration and development activities and do not include any costs related to production or general overhead expenses. These costs along with estimated future capital costs that are based on current costs and that are incurred in developing proved reserves are depleted and depreciated on a unit of production basis using estimated proved petroleum and natural gas reserves, with both production and reserves stated before royalties. For purposes of this calculation, petroleum and natural gas reserves are converted to a common unit of measurement on the basis of their relative energy content where six thousand cubic feet of gas equates to one barrel of oil. Costs of acquiring and evaluating unproved properties are excluded from costs subject to depletion and depreciation until it is determined whether proved reserves are attributable to the properties or impairment occurs. Unproved properties are evaluated for impairment on an annual basis.

Gains or losses on the disposition of petroleum and natural gas properties are recognized only when crediting the proceeds to costs would result in a change of 20 percent or more in the depletion rate.

The net amount at which petroleum and natural gas properties are carried is subject to a cost recovery test (the "ceiling test"). The ceiling test is a two-stage process which is to be performed at least annually. The first stage of the test is a recovery test which compares the undiscounted future cash flow from proved reserves at forecast prices plus the cost less impairment of unproved properties to the net book value of the petroleum and natural gas assets to determine if the assets are impaired. An impairment loss exists when the net book value of the petroleum and natural gas assets exceeds such undiscounted cash flow. The second stage determines the amount of the impairment loss to be recorded. The impairment is measured as the amount by which the net book value of the petroleum and natural gas assets exceeds the future discounted cash flow from proved plus probable reserves at forecast prices. Any impairment is recorded as additional depletion and depreciation.

Goodwill

Goodwill is the residual amount that results when the purchase price of an acquired business exceeds the fair value for accounting purposes of the net identifiable assets and liabilities of the acquired business. Goodwill is stated at cost less impairment and is not amortized. The goodwill balance is assessed for impairment annually at year-end or more frequently if events or changes in circumstances indicate that the asset may be impaired. The test for impairment is conducted by the comparison of the net book value to the fair value of the reporting entity. If the fair value of the Trust is less than the net book value, impairment is deemed to have occurred. The extent of the impairment is measured by allocating the fair value of the Trust to the identifiable assets and liabilities at their fair values. Any remainder of this allocation is the implied value of goodwill. Any excess of the net book value of goodwill over this implied value is the impairment amount. Impairment is charged to income in the period in which it occurs.

Convertible Unsecured Subordinated Debentures

The debentures have been classified as debt net of the fair value of the conversion feature which has been classified as unitholders' equity. Issue costs will be amortized over the term of the debentures, and the debt portion will accrete up to the principal balance at maturity. The accretion, amortization of issue costs and the interest paid are expensed as interest expense in the consolidated statements of operations. If the debentures are converted to trust units, a portion of the value of the conversion feature under unitholders' equity will be reclassified to unitholders' capital along with the principal amounts converted.

Asset Retirement Obligation

The Trust recognizes a liability at discounted fair value for the future abandonment and reclamation costs associated with the petroleum and natural gas properties. The fair value of the liability is capitalized as part of the cost of the related asset and amortized to expense over its useful life. The liability accretes until the date of expected settlement of the retirement obligations. The related accretion expense is recognized in the statement of operations. The provision will be revised for the effect of any changes to timing related to cash flow or undiscounted abandonment costs. Actual expenditures incurred for the purpose of site reclamation are charged to the asset retirement obligations to the extent that the liability exists on the balance sheet. Differences between the actual costs incurred and the fair value of the liability recorded are recognized in income in the period the actual costs are incurred.

Joint Interests

A portion of the Trust's exploration, development and production activities is conducted jointly with others. These consolidated financial statements reflect only the Trust's proportionate interest in such activities.

Foreign Currency Translation

Foreign currency denominated monetary items are translated into Canadian dollars at the exchange rate in effect at the balance sheet date. Exchange gains and losses on long-term monetary items that do not qualify for hedge accounting are recognized in income.

Revenue and expenses are translated at the monthly average rate of exchange. Translation gains and losses are included in net income.

Deferred Charges and Other Assets

Financing costs related to the exchange of the senior subordinated notes have been deferred and are amortized over the term of the notes on a straight-line basis.

Revenue Recognition

Revenue associated with sales of crude oil, natural gas and natural gas liquids is recognized when title passes to the purchaser, normally at the pipeline delivery point for natural gas and at the wellhead for crude oil.

Financial Derivative Contracts

The Trust formally documents its risk management objectives and strategies to manage exposures to fluctuations in commodity prices, interest rates and foreign currency exchange rates. The risk management policies included the permitted use of derivative financial instruments, including swaps and collars, used to manage these fluctuations. All transactions of this nature entered into by the Trust are related to an underlying financial instrument or to future petroleum and natural gas production. The Trust does not use financial derivatives for trading or speculative purposes. Financial derivative contracts used as hedging transactions must be documented and it must be demonstrated that the hedges are sufficiently effective in order to continue accrual accounting for positions hedged with financial

derivative contracts. Financial derivative contracts that do not qualify for hedge accounting are recognized in the balance sheet and measured at fair value, with changes in fair value reported separately in the statement of operations as income or expense.

Future Income Taxes

The Trust is a unit trust for income tax purposes, and is taxable on taxable income not allocated to the unitholders. From inception on September 2, 2003, the Trust has allocated all of its taxable income to the unitholders, and accordingly, no provision for income taxes is required at the Trust level.

The Company is subject to corporate income taxes and follows the liability method of accounting for income taxes. Income taxes are accounted for under the liability method of tax allocation, which determines future income taxes based on the differences between assets and liabilities reported for financial accounting purposes and those reported for tax purposes. Future income taxes are calculated using tax rates anticipated to apply in periods that temporary differences are expected to reverse.

Unit-based Compensation

The Trust Unit Rights Incentive Plan is described in note 12. The exercise price of the rights granted under the Plan may be reduced in future periods in accordance with the terms of the Plan. The Trust uses the Black-Scholes option-pricing model to calculate the estimated fair value of the outstanding rights.

Compensation expense associated with rights granted under the plan is recognized in income over the vesting period of the plan with a corresponding increase in contributed surplus. The exercise of trust unit rights are recorded as an increase in trust units with a corresponding reduction in contributed surplus.

Non-controlling Interest

The exchangeable shares of the Company are presented as a non-controlling interest on the consolidated balance sheet because they fail to meet the non-transferability criteria necessary in order for them to be classified as equity. Net income has been reduced by an amount equivalent to the non-controlling interest proportionate share of the Trust's consolidated net income with a corresponding increase to the non-controlling interest on the consolidated balance sheet. As the exchangeable shares are converted to Trust units, the exchange is accounted for as a step-acquisition where Unitholders' capital was increased by the fair value of the Trust units issued. The difference between the fair value of the Trust units issued and the book value of the exchangeable shares is recorded as an increase in petroleum and natural gas properties.

Per-unit Amounts

Basic net income per unit is computed by dividing net income by the weighted average number of trust units outstanding during the year. Diluted per unit amounts reflect the potential dilution that could occur if trust unit rights were exercised or exchangeable shares were converted or convertible debentures were fully converted. The treasury stock method is used to determine the dilutive effect of trust unit rights, whereby any proceeds from the exercise of trust unit rights or other dilutive instruments and the amount of compensation expense, if any, attributed to future services and not yet recognized are assumed to be used to purchase trust units at the average market price during the period.

3. CHANGES IN ACCOUNTING POLICIES

Unit-Based Compensation

Until July 1, 2005, the Trust accounted for unit based compensation based on the intrinsic value of the grants at each reporting date. Effective July 1, 2005, on a prospective basis, the Trust began valuing unit rights using the fair value based method. In the fourth quarter of 2005, the Trust determined that the fair value methodology should have been applied to all grants since CICA 3870 was adopted, and the financial statements of prior periods have been restated accordingly.

As a result of retroactively adopting the fair value method of estimating compensation expense, net income for the comparative year ended December 31, 2004 was increased by $3.0 million, net of non-controlling interest of $0.09 million. The opening 2004 accumulated deficit decreased by $1.7 million, net of non-controlling interest of $0.1 million. There was also a decrease in unitholders' capital of $0.07 million during 2004 relating to the transfer of value from contributed surplus on exercise of unit option rights. There was no impact on cash flow as a result of adopting this policy (note 12).

4. CORPORATE ACQUISITION

Effective September 22, 2004, the Company acquired all of the issued and outstanding shares of a private oil and gas company with operations in Alberta. The transaction was accounted for using the purchase method of accounting. The estimated fair value of the assets acquired and liabilities assumed at the date of acquisition is summarized below. Subsequent to the acquisition, the private company was amalgamated with the Company.

Petroleum and natural gas properties	$	109,777
Goodwill		37,755
Working capital		2,951
Capital lease obligation		(777)
Asset retirement obligation		(8,435)
Future income taxes		(30,229)
Total net assets acquired	$	111,042
Financed by:		
Cash	$	110,822
Costs associated with acquisition		220
Total purchase price	$	111,042

Goodwill of $37.8 million was determined based on the excess of the total consideration paid less the value assigned to the identifiable assets and liabilities including the future income tax liability.

5. PETROLEUM AND NATURAL GAS PROPERTIES

As at December 31,	2005	2004
Petroleum and natural gas properties	$ 2,461,045	$ 2,342,514
Accumulated depletion and depreciation	(1,491,307)	(1,332,581)
	$ 969,738	$ 1,009,933

In calculating the depletion and depreciation provision for 2005, $46.6 million (2004 – $61.7 million) of costs relating to undeveloped properties and materials were excluded from costs subject to depletion and depreciation. No general and administrative expenses have been capitalized since the inception of operations as a trust effective September 2, 2003.

The petroleum and natural gas properties are subject to a ceiling test, which was calculated at December 31, 2005 using the following benchmark reference prices for the years 2006 to 2010 adjusted for commodity differentials specific to the Trust (note 18):

	2006	2007	2008	2009	2010
WTI *(US$/bbl)*	60.81	61.61	54.60	50.19	47.76
AECO *(CAD$/MMBtu)*	11.58	10.84	8.95	7.87	7.57

The prices and costs subsequent to 2010 have been adjusted for inflation at an annual rate of 1.5 percent. Based on the ceiling test calculation, the Trust's estimated undiscounted future net cash flows associated with the proved reserves plus the cost less impairment of unproved properties exceeded the book value of the petroleum and natural gas properties.

6. BANK CREDIT FACILITIES

The Company has a credit agreement with a syndicate of chartered banks. The credit facilities consist of an operating loan and a 364-day revolving loan. Advances under the credit facilities or letters of credit (note 18) can be drawn in either Canadian or U.S. funds and bear interest at the agent bank's prime lending rate, bankers' acceptance rates plus applicable margins or LIBOR rates plus applicable margins. The facilities aggregating $250 million are subject to semi-annual review and are secured by a floating charge over all of the Company's assets. At December 31, 2005 a total of $123.6 million had been drawn under the credit facilities.

7. LONG-TERM DEBT

As at December 31,	2005	2004
10.5% senior subordinated notes (US$247,000)	$ 288	$ 297
9.625% senior subordinated notes (US$179,699,000)	209,511	216,286
	$ 209,799	$ 216,583

Senior Subordinated Notes

The Company has US$247,000 senior subordinated notes bearing interest at 10.5 percent payable semi-annually with principal repayable on February 15, 2011. These notes are unsecured and are subordinate to the Company's bank credit facilities.

US$179.7 million of 9.625 percent senior subordinated notes due July 15, 2010 are unsecured and are subordinate to the Company's bank credit facilities. The Company entered into an interest rate swap contract converting the fixed rate to a floating rate reset quarterly at the three month LIBOR rate plus 5.2 percent until the maturity of these notes.

Interest Expense

The Company incurred interest expense on its outstanding debt as follows:

	2005	2004
Bank loan	$ 8,318	$ 2,256
Amortization of deferred charges	1,492	1,060
Long-term debt	23,314	16,096
Total interest	$ 33,124	$ 19,412

8. CONVERTIBLE UNSECURED SUBORDINATED DEBENTURES

On June 6, 2005 the Trust issued $100 million principal amount of 6.5% convertible unsecured subordinated debentures for net proceeds of $95.8 million. The debentures pay interest semi-annually and are convertible at the option of the holder at any time into fully paid trust units at a conversion price of $14.75 per trust unit. The debentures mature on December 31, 2010 at which time they are due and payable.

The debentures have been classified as debt net of the fair value of the conversion feature which has been classified as unitholders' equity. This resulted in $95.2 million being classified as debt and $4.8 million being classified as equity. Issue costs are being amortized over the term of the debentures, and the debt portion will accrete up to the principal balance at maturity. The accretion, amortization of issue costs and the interest paid are expensed as interest expense in the consolidated statements of operations. If the debentures are converted to trust units, a portion of the value of the conversion feature under unitholders' equity will be reclassified to unitholders' capital along with the principal amounts converted.

Debentures issued on June 6, 2005	$ 100,000
Fair value of conversion feature	(4,800)
Conversion of Debentures and amortization of discount	(21,434)
Debentures outstanding December 31, 2005	$ 73,766

9. ASSET RETIREMENT OBLIGATIONS

	2005	2004
Balance, beginning of the year	$ 73,297	$ 55,996
Liabilities incurred	406	4,623
Liabilities settled	(1,637)	(2,739)
Acquisition of liabilities	3,410	12,797
Disposition of liabilities	(2,117)	(1,722)
Accretion	5,762	4,342
Change in estimate (1)	(46,111)	–
Balance, end of the year	$ 33,010	$ 73,297

(1) The change in estimate was primarily due to the significant increase in recent and forecasted market price of petroleum and natural gas. Consequentially, the projected economic life of the wells and facilities are extended, resulting in wells and facilities being abandoned and reclaimed further out in the future and thus a lower present value of asset retirement obligations.

The Trust's asset retirement obligations are based on the Trust's net ownership in wells and facilities. Management estimates the costs to abandon and reclaim the wells and the facilities and the estimated time period during which these costs will be incurred in the future. These costs are expected to be incurred over the next 52 years with the majority of costs incurred between 2044 and 2057. The undiscounted amount of estimated cash flow required to settle the retirement obligations at December 31, 2005 is $218 million. Estimated cash flow has been discounted at a credit-adjusted risk free rate of 8.0 percent and an inflation rate of 2.5 percent for the years 2006 to 2008, and 1.5 percent thereafter.

10. UNITHOLDERS' CAPITAL

Trust Units

The Trust is authorized to issue an unlimited number of trust units.

Trust Units	*Number of Units*	*Amount*
Balance December 31, 2003	60,821	$ 449,403
Issued on conversion of Exchangeable Shares	1,994	21,222
Issued on exercise of trust unit rights	113	1,005
Transfer from contributed surplus on exercise of trust unit rights *(restated – note 3)*	–	402
Issued pursuant to distribution reinvestment program	10	131
Issued for cash, net of expenses	3,600	43,500
Balance December 31, 2004	66,538	515,663
Issued on conversion of Debentures	1,549	22,859
Issued on conversion of Exchangeable Shares	363	5,373
Issued on exercise of trust unit rights	369	2,916
Transfer from contributed surplus on exercise of trust unit rights	–	1,301
Issued pursuant to distribution reinvestment program	464	6,908
Balance December 31, 2005	69,283	$ 555,020

On October 18, 2004, the Trust implemented a Distribution Reinvestment Plan ("DRIP"). Under the DRIP, Canadian unitholders are entitled to reinvest monthly cash distributions in additional trust units of the Trust. At the discretion of the Trust, these additional units will be issued from treasury at 95% of the "weighted average closing price", or acquired on the market at prevailing market rates. For the purposes of the units issued from treasury, the "weighted average closing price" is calculated as the weighted average trading price of trust units for the period commencing on the second business day after the distribution record date and ending on the second business day immediately prior to the distribution payment date, such period not to exceed 20 trading days. The Trust can also acquire trust units to be issued under the DRIP at prevailing market rates.

On December 20, 2004, the Trust issued 3,600,000 trust units at $12.80 per unit for gross proceeds of $46.1 million pursuant to a prospectus.

11. NON-CONTROLLING INTEREST

The Company is authorized to issue an unlimited number of exchangeable shares. The exchangeable shares can be converted (at the option of the holder) into trust units at any time up to September 2, 2013. Up to 1.9 million exchangeable shares may be redeemed annually by the Company for either cash or the issue of trust units. The number of trust units issued upon conversion is based upon the exchange ratio in effect at the conversion date. The exchange ratio is adjusted monthly based on the cash distribution paid divided by the weighted average trust unit price for the five-day trading period ending on the record date. The exchange ratio at December 31, 2005 was 1.37201 trust units per exchangeable share (2004 – 1.21472 trust units per exchangeable share). Cash distributions are not paid on the exchangeable shares. The exchangeable shares are not publicly traded, although they may be transferred by the holder without first being converted to trust units.

The exchangeable shares of the Company are presented as a non-controlling interest on the consolidated balance sheet because they fail to meet the non-transferability criteria necessary in order for them to be classified as equity. Net income has been reduced by an amount equivalent to the non-controlling interest proportionate share of the Trust's consolidated net income with a corresponding increase to the non-controlling interest on the balance sheet.

Non-controlling Interest	*Number of Exchangeable Shares*	*Amount*
Balance December 31, 2003 *(restated – note 3)*	3,725	$ 25,590
Exchanged for trust units	(1,849)	(13,090)
Non-controlling interest in net income	–	436
Balance December 31, 2004 *(restated – note 3)*	1,876	12,936
Exchanged for trust units	(279)	(1,975)
Non-controlling interest in net income	–	1,849
Balance December 31, 2005	1,597	$ 12,810

As the exchangeable shares are converted to Trust units, the exchange is accounted for as a step-acquisition where Unitholders' capital was increased by the fair value of the Trust units issued. The difference between the fair value of the Trust units issued and the book value of the exchangeable shares is recorded as an increase in petroleum and natural gas properties.

12. TRUST UNIT RIGHTS

The Trust has a Trust Unit Rights Incentive Plan (the "Plan") whereby the maximum number of trust units issuable pursuant to the plan is a "rolling" maximum equal to 10% of the outstanding trust units plus the number of trust units which may be issued on the exchange of outstanding exchangeable shares. Any increase in the issued and outstanding units will result in an increase in the available number of trust units issuable under the plan, and any exercises of incentive rights will make new grants available under the plan, effectively resulting in a re-loading of the number of rights available to grant under the plan. Trust unit rights are granted at the volume weighted average trading price of the trust units for the five trading days prior to the date of grant, vest over three years and have a term of five years. The Plan provides for the exercise price of the rights to be reduced in future periods by a portion of the future distributions.

The Trust recorded compensation expense of $5.3 million for the year ending December 31, 2005 ($4.6 million in 2004) (note 3).

The Trust used the Black-Scholes option-pricing model to calculate the estimated fair value of the outstanding rights. The following assumptions were used to arrive at the estimate of fair values:

	2005	2004
Expected annual right's exercise price reduction	$ 1.80	$ 1.80
Expected volatility	23%	30%
Risk-free interest rate	3.30% – 3.84%	3.59% – 4.31%
Expected life of option *(years)*	5	5

The number of unit rights issued and exercise prices are detailed below:

	Number of rights	*Weighted average exercise price* (1)
Balance, December 31, 2003	2,855	$ 10.15
Granted	1,297	$ 11.77
Exercised	(113)	$ 8.87
Cancelled	(502)	$ 9.54
Balance, December 31, 2004	3,537	$ 9.60
Granted	2,451	$ 15.01
Exercised	(369)	$ 7.90
Cancelled	(253)	$ 9.83
Balance, December 31, 2005	5,366	$ 10.88

(1) Exercise price reflects grant prices less reduction in exercise price as discussed above.

The following table summarizes information about the unit rights outstanding at December 31, 2005:

Range of Exercise Prices	*Number Outstanding at December 31, 2005*	*Weighted Average Remaining Term (years)*	*Weighted Average Exercise Price*	*Number Exercisable at December 31, 2005*	*Weighted Average Exercise Price*
$ 5.41 to $ 8.50	1,959	2.7	$ 6.60	1,136	$ 6.57
$ 8.51 to $11.50	1,028	3.8	$ 10.45	323	10.45
$11.51 to $14.50	472	4.4	$ 12.57	–	–
$14.51 to $17.68	1,907	4.8	$ 15.08	–	–
$ 5.41 to $17.68	5,366	3.8	$ 10.88	1,459	$ 7.43

13. NET INCOME PER UNIT

The Trust applies the treasury stock method to assess the dilutive effect of outstanding trust unit rights on net income per unit. The weighted average exchangeable shares outstanding during the year, converted at the year-end exchange ratio, and the trust units issuable on conversion of convertible debentures, have also been included in the calculation of the diluted weighted average number of trust units outstanding:

	2005	2004
Weighted average number of units outstanding, basic	67,382	62,574
Trust units issuable on conversion of exchangeable shares	2,330	2,635
Dilutive effect of trust unit incentive rights	1,438	473
Trust units issuable on conversion of convertible debentures	2,981	–
Weighted average number of units outstanding, diluted	74,131	65,682

The dilutive effect of trust unit incentive rights above did not include 3.9 million trust unit rights (2004 – 3.1 million) because the respective exercise prices exceeded the average market price of the trust units during the year and the amount of compensation expense attributed to future services and not yet recognized.

14. INCOME TAXES (RECOVERY)

The provision for (recovery of) income taxes has been computed as follows:

	2005	2004 (1)
		(restated – note 3)
Income (loss) before income taxes and		
non-controlling interest	$ 83,398	$ (15,037)
Expected income taxes (recovery) at the statutory rate		
of 40.10% (2004 – 40.57%)	33,443	(6,101)
Increase (decrease) in taxes resulting from:		
Resource allowance	(13,650)	(9,663)
Alberta royalty tax credit	(130)	(203)
Net income of the Trust	(29,415)	(30,097)
Non-taxable portion of foreign exchange gain	(1,360)	(3,241)
Effect of change in tax rate	2,734	(7,438)
Effect of change in opening tax pool balances	851	8,711
Effect of change in valuation allowance	(1,400)	5,194
Unit based compensation	2,143	1,696
Other	(290)	(95)
Large corporation tax and provincial capital tax	8,747	9,000
Provision for (recovery of) income taxes	$ 1,673	$ (32,237)

(1) Certain comparative figures have been reclassified to conform to the current year's presentation.

The components of future income taxes are as follows:

As at December 31,		2005		2004
Future income tax liabilities:				
Capital assets	$	170,008	$	193,584
Other		13,304		12,853
Future income tax assets:				
Asset retirement obligation		(11,917)		(26,072)
Reorganization costs		(7,212)		(12,206)
Loss carry-forward		(4,438)		(3,250)
Future income taxes	$	159,745	$	164,909

15. CASH FLOW INFORMATION

Increase (Decrease) in Non-Cash Working Capital Items

		2005		2004
Current assets	$	(35,401)	$	(6,055)
Current liabilities		16,410		5,630
	$	(18,991)	$	(425)
Changes in non cash working capital related to:				
Operating activities	$	(20,212)	$	3,589
Investing activities		1,221		(4,014)
	$	(18,991)	$	(425)

During the year the Trust made the following cash outlays in respect of interest expense and current income taxes.

		2005		2004
Interest	$	29,728	$	21,096
Current income taxes	$	8,536	$	17,485

16. FINANCIAL INSTRUMENTS AND CREDIT RISK

The Trust's financial instruments recognized in the balance sheet consist of cash and short-term investments, accounts receivable, current liabilities and long-term borrowings. The estimated fair values of the financial instruments have been determined based on the Trust's assessment of available market information and appropriate valuation methodologies; however, these estimates may not necessarily be indicative of the amounts that could be realized or settled in a market transaction.

The fair values of financial instruments other than bank debt and long-term borrowings approximate their book amounts due to the short-term maturity of these instruments. The fair value of the bank debt approximates its book value as it is at a market rate of interest. At December 31, 2005, the trading value of the Company's senior subordinated term notes was 105 percent in relation to par (2004 – 105 percent). The market value of the Trust's convertible debentures at December 31, 2005 was 118 percent in relation to par.

Most of the Trust's accounts receivable relate to oil and natural gas sales and are exposed to typical industry credit risks. The Trust manages this credit risk by entering into sales contracts with only credit worthy entities and reviewing its exposure to individual entities on a regular basis. The book value of the accounts receivable reflects management's assessment of the associated credit risks.

The Trust is exposed to interest rate risk as a result of its floating rate debts.

17. FINANCIAL DERIVATIVE CONTRACTS

The nature of the Trust's operations results in exposure to fluctuations in commodity prices, exchange rates and interest rates. The Trust monitors and, when appropriate, utilizes derivative contracts to manage its exposure to these risks. The Trust is exposed to credit-related losses in the event of non-performance by counter-parties to these contracts.

At December 31, 2005, the Trust had derivative contracts for the following:

OIL	*Period*	*Volume*	*Price*	*Index*
Price collar	Calendar 2006	2,000 bbl/d	US$55.00 – $80.85	WTI
Price collar	Calendar 2006	2,000 bbl/d	US$55.00 – $84.18	WTI
Price collar	Calendar 2006	2,000 bbl/d	US$55.00 – $85.30	WTI
Price collar	Calendar 2006	1,000 bbl/d	US$55.00 – $87.10	WTI
Price collar	Calendar 2006	1,000 bbl/d	US$55.00 – $87.35	WTI

FOREIGN CURRENCY	*Period*	*Amount*	*Floor*	*Cap*
Collar	Calendar 2006	US$3,000,000 per month	CAD/US$1.1700	CAD/US$1.2065

INTEREST RATE SWAP	*Period*	*Principal*	*Rate*
	November 2003 to July 2010	US$179,699,000	3-month LIBOR plus 5.2%

Under the CICA guideline for hedge accounting, the Trust's financial derivative contracts for oil collars do not qualify as effective accounting hedges. Accordingly, these contracts have been accounted for based on the fair value method. At December 31, 2005, the Trust recorded an asset of $5.2 million (2004 – a liability of $9.5 million) on the mark-to-market value of the outstanding non-hedging financial derivatives. The change in the mark-to-market value of the non-hedging financial derivatives during 2005 has been recorded as an unrealized gain on non-hedging financial derivatives of $14.7 million (2004 – $0.6 million) in the consolidated statement of operations. The Trust is applying hedge accounting to the interest rate swap and gains and losses are netted against interest expense.

In 2006, the Company entered into derivative contracts for the following:

OIL	*Period*	*Volume*	*Price*	*Index*
Price collar	Calendar 2007	2,000 bbl/d	US$55.00 – $83.60	WTI
Price collar	Calendar 2007	3,000 bbl/d	US$55.00 – $83.75	WTI

FOREIGN CURRENCY	*Period*	*Amount*	*Floor*	*Cap*
Collar	February 1, 2006 to December 31, 2006	US$4,000,000 per month	CAD/US$1.1500	CAD/US$1.1835
Collar	January 9, 2006 to December 31, 2006	US$3,000,000 per month	CAD/US$1.1500	CAD/US$1.1780

18. COMMITMENTS AND CONTINGENCIES

In October 2002, the Trust entered into a long-term crude oil supply contract with a third party that requires the delivery of up to 20,000 barrels per day of Lloydminster Blend crude oil at a price fixed at 71% of NYMEX WTI oil price. The contract is for an initial term of five years commencing January 1, 2003. The contract volumes increased from 9,000 barrels per day in January 2003 to 20,000 barrels per day in October 2003 and thereafter.

At December 31, 2005, the Trust had entered into natural gas physical sales contracts with third parties as follow:

GAS	*Period*	*Volume*	*Price*
Fixed price	January 1, 2006 to February 28, 2006	3,000 GJ/d	CAD$10.00
Fixed price	January 1, 2006 to March 31, 2006	5,000 GJ/d	CAD$10.07
Fixed price	January 1, 2006 to March 31, 2006	5,000 GJ/d	CAD$10.20
Fixed price	January 1, 2006 to March 31, 2006	2,000 GJ/d	CAD$10.63
Fixed price	March 1, 2006 to March 31, 2006	3,000 GJ/d	CAD$11.53
Fixed price	April 1, 2006 to October 31, 2006	5,000 GJ/d	CAD$8.40
Fixed price	April 1, 2006 to October 31, 2006	2,000 GJ/d	CAD$9.01
Price collar	January 1, 2006 to October 31, 2006	5,000 GJ/d	CAD$7.50 – $13.40
Price collar	April 1, 2006 to October 31, 2006	2,000 GJ/d	CAD$7.80 – $10.55
Price collar	April 1, 2006 to October 31, 2006	3,000 GJ/d	CAD$9.50 – $12.60

At December 31, 2005, the Trust had operating lease and transportation obligations as detailed below:

($ thousands)	*Payments Due*			
	Total	*Within 1 year*	*1–3 years*	*4–5 years*
Operating leases	8,117	1,621	5,834	662
Transportation agreements	3,446	2,052	1,394	–
Total	11,563	3,673	7,228	662

At December 31, 2005, there are outstanding letters of credit aggregating $7.1 million issued as security for performance under certain contracts.

The Company has future contractual processing obligations with respect to assets acquired. The fair value ($7.8 million) of the original obligation is being drawn down over the life of the obligations which continue until October 2008.

The Trust is engaged in litigation and claims arising in the normal course of operations, none of which could reasonably be expected to materially affect the Trust's financial position or reported results of operations.

19. DIFFERENCES BETWEEN CANADIAN AND UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The consolidated financial statements have been prepared in accordance with Canadian Generally Accepted Accounting Principles ("GAAP"), which differ in some respects from GAAP in the United States. The significant differences in GAAP, as applicable to these consolidated financial statements and notes, are described in the Trust's Form 40-F, which is filed with the United States Securities and Exchange Commission.

RESERVES DATA

The following table summarizes certain information with regard to Baytex's oil and gas reserves as evaluated by Sproule Associates Limited as at December 31, 2005. Additional information required under NI 51-101 is included in the Annual Information Form for fiscal 2005.

Summary of Oil and Gas Reserves (Forecast Prices and Costs)

As at December 31, 2005	*Light and Medium Oil*		*Heavy Oil*	
	Gross (1)	*Net (2)*	*Gross (1)*	*Net (2)*
	(Mbbl)	*(Mbbl)*	*(Mbbl)*	*(Mbbl)*
Proved				
Developed producing	3,281	2,963	23,135	20,389
Developed non-producing	531	437	19,409	16,477
Undeveloped	1,660	1,417	28,722	25,339
Total proved	5,472	4,817	71,266	62,205
Probable	2,342	2,100	26,286	22,450
Total proved plus probable	7,814	6,917	97,552	84,655

Notes:

(1) "Gross" reserves are the working interest share of remaining reserves, before deduction of any royalties and excluding any royalty interest.

(2) "Net" reserves means Baytex's gross reserves less all royalties payable to others.

(3) Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Reconciliation of Working Interest Reserves (1)
By Principal Product Type (Forecast Prices and Costs)

	Light and Medium Oil			*Heavy Oil*		
Factors	*Proved*	*Probable*	*Proved + Probable*	*Proved*	*Probable*	*Proved + Probable*
	(Mbbl)	*(Mbbl)*	*(Mbbl)*	*(Mbbl)*	*(Mbbl)*	*(Mbbl)*
December 31, 2004	6,386	2,431	8,817	55,874	24,887	80,761
Extensions	340	43	383	7,009	3,498	10,507
Discoveries	19	12	31	426	175	601
Technical revisions	(505)	(183)	(688)	520	(4,148)	(3,628)
Acquisitions	–	–	–	15,777	1,776	17,553
Dispositions	–	–	–	(1,800)	(300)	(2,100)
Economic factors	102	39	141	894	398	1,292
Production	(870)	–	(870)	(7,434)	–	(7,434)
December 31, 2005	5,472	2,342	7,814	71,266	26,286	97,552

Notes:

(1) Working interest reserves include solution gas but do not include royalty interest.

(2) Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Natural Gas Liquids		Natural Gas		Oil Equivalent (2)	
Gross (1)	Net (2)	Gross (1)	Net (2)	Gross (1)	Net (2)
(Mbbl)	(Mbbl)	(Bcf)	(Bcf)	(Mboe)	(Mboe)
2,343	2,030	94.9	79.7	44,576	38,659
677	568	11.6	9.5	22,553	19,075
615	485	19.0	14.1	34,168	29,591
3,635	3,083	125.5	103.3	101,297	87,325
1,254	1,022	50.9	42.6	38,360	32,665
4,889	4,105	176.4	145.9	139,657	119,990

Natural Gas Liquids			Natural Gas			Oil Equivalent (2)		
Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
(Mbbl)	(Mbbl)	(Mbbl)	(MMcf)	(MMcf)	(MMcf)	(Mboe)	(Mboe)	(Mboe)
3,672	590	4,262	110,999	44,101	155,100	84,432	35,258	119,690
1,113	664	1,777	19,691	8,315	28,006	11,744	5,591	17,335
149	17	166	1,636	213	1,849	867	240	1,107
(825)	(26)	(861)	8,631	(3,770)	4,861	629	(4,985)	(4,356)
–	–	–	4,856	1,297	6,153	16,586	1,992	18,578
–	–	–	–	–	–	(1,800)	(300)	(2,100)
59	9	68	1,776	706	2,482	1,351	564	1,915
(533)	–	(533)	(22,052)	–	(22,052)	(12,512)	–	(12,512)
3,635	1,254	4,889	125,537	50,862	176,399	101,297	38,360	139,657

Reserve Life Index

	2006 Production Target	Reserve Life Index (years) Total Proved	Proved Plus Probable
Oil and NGL *(bbl/d)*	24,800	8.9	12.2
Natural gas *(MMcf/d)*	61.2	5.6	7.9
Oil equivalent *(boe/d)*	35,000	7.9	11.0

Net Present Value of Reserves (Forecast Prices and Costs)

	Summary of Net Present Value of Future Net Revenue As at December 31, 2005 Forecast Prices and Costs Before Income Taxes Discounted at (percent/year)		
Reserves Category ($ million)	*0 percent*	*5 percent*	*10 percent*
Proved			
Developed producing	1,068.3	979.0	883.8
Developed non-producing	400.7	303.1	239.4
Undeveloped	508.0	368.5	276.0
Total proved	1,977.0	1,650.6	1,399.2
Probable	788.1	526.2	385.5
Total proved plus probable	2,765.1	2,176.8	1,784.7

Sproule December 31, 2005 Price Forecast

Year	WTI Cushing US$/bbl	Edmonton Par Price C$/bbl	Hardisty Heavy 12 API C$/bbl	AECO-C Spot C$/MMBtu	Inflation Rate %/Year	Exchange Rate USD/C$
2006	60.81	70.07	37.07	11.58	2.5	0.8500
2007	51.61	70.99	37.29	10.84	2.5	0.8500
2008	54.60	62.73	34.23	8.95	2.5	0.8500
2009	50.19	57.53	32.27	7.87	1.5	0.8500
2010	47.76	54.65	31.15	7.57	1.5	0.8500
2011	48.48	55.47	31.94	7.70	1.5	0.8500
2012	49.20	56.31	32.74	7.83	1.5	0.8500
2013	49.94	57.16	33.56	7.96	1.5	0.8500

Thereafter prices are escalated at 1.5% per year.

The Board of Directors and Management of Baytex are committed to ensuring proper corporate governance practices that meet current regulatory requirements.

Baytex complies and will continue to comply with all applicable regulations with a goal of providing transparency and accountability in our corporate governance practices.

MANDATE OF THE BOARD

The board of directors of Baytex is responsible for the stewardship of Baytex and the Trust and their subsidiaries. The board's mandate includes:

- the review and approval of the strategic direction of the Trust, its capital and financial plans, as well as implementation and monitoring of appropriate risk management systems;
- monitoring the progress, policies and procedures of the Trust, while providing guidance and advice to management and providing approval for any significant changes in the organizational structure;
- ensuring that the finances and controls of the Trust are appropriate and comply with required standards, including accurate, complete and timely disclosure of information to unitholders, other security holders and regulators; and
- annual reviews of the composition and compensation of the board, and monitoring its effectiveness, continuity and independence while ensuring the requirements of the board are continuously upheld.

The board of directors holds regularly scheduled meetings to review the business affairs of Baytex. The Chairman of the board is an independent director and has a separate role from that of the President and Chief Executive Officer.

BOARD COMPOSITION

The board of directors of Baytex is currently composed of seven members, all of whom are independent and not members of management except for Mr. Raymond Chan, President and Chief Executive Officer.

COMMITTEES

Individual directors are appointed by the board to sit on certain designated committees including the Audit Committee, Reserves Committee and Compensation Committee. Each committee has a written board approved mandate outlining its purpose, membership, responsibility and accountability.

Audit Committee

The Audit Committee has responsibility for overseeing:

- the nature and scope of the annual audit;
- management's reporting on internal accounting standards and practices;
- financial information and accounting systems and procedures;
- financial reporting and statements; and
- recommending for board approval the interim and audited annual financial statements and other mandatory disclosure containing financial information.

The Audit Committee is comprised of three directors, none of whom is a member of the management of Baytex and all of whom are independent and financially literate. The Audit Committee meets at least quarterly and may meet more frequently as required.

Reserves Committee

The Reserves Committee has responsibility for:

- reviewing disclosure requirements and procedures with respect to the oil and gas activities of the Trust including those set forth under applicable securities legislation including National Instrument 51-101;
- reviewing procedures for providing information to the independent reserves evaluator;
- reviewing the appointment of the independent evaluator;
- recommending to the board of directors the approval of the annual independent reserves evaluation report and related information; and
- reviewing generally all matters relating to the preparation and public disclosure of reserves estimates.

The Reserves Committee is comprised of three directors, none of whom are members of the management of Baytex and all of whom are independent. Each member of the Reserves Committee has sufficient technical knowledge of oil and natural gas reserves to perform their duties under this committee. The Reserves Committee meets at least annually and may meet more frequently as required.

Compensation Committee

The Compensation Committee has the responsibility to review matters relating to the human resource policies and compensation of all directors, officers and employees of Baytex in the context of the approved budget and business plan. The Compensation Committee formulates and makes recommendations to the board regarding compensation and human resource issues.

The Compensation Committee is comprised of three directors, all of whom are independent. The Compensation Committee meets at least annually and may meet more frequently as required.

CORPORATE GOVERNANCE POLICIES

Policy on Business Conduct and Ethics

The Baytex Policy on Business Conduct and Ethics is a statement of the principles to which Baytex is committed and is designed to direct all employees, officers and directors in the practice of ethical business conduct. The policy is a guide to the standards of behavior that we require in all of our business activities. Directors, officers and employees must know these standards and agree annually in writing to comply with the policy. The policy not only applies to Baytex employees, officers and directors but also to independent contractors to the extent that they conduct activities on behalf of Baytex.

Disclosure, Confidentiality and Trading Policy

The Disclosure, Confidentiality and Trading Policy establishes procedures to permit the appropriate disclosure of information to the public in an informative, timely and broadly disseminated manner. The policy also ensures that non-public information remains confidential and that trading of Baytex securities by directors, officers and employees is conducted in compliance with applicable securities laws.

Whistle Blower Policy

Baytex is committed to maintaining the highest standards of honesty and accountability in its business activities. Our employees, officers and directors are likely to be the first to know when someone inside the Company or connected with the Company is acting improperly or illegally. Baytex maintains a procedure for the reporting of ethical violations which encourages all Baytex employees to report any misconduct. The procedure ensures that Baytex employees may report misconduct without the threat or fear of dismissal, harassment or other retaliation.

Code of Ethics for Principal Executive Officer and Senior Financial Officers

While Baytex and its unitholders expect honest and ethical conduct in all aspects of our business from all employees, officers and directors, Baytex and its unitholders expect the highest possible standard from our financial managers. This code of ethics is applicable to the President and Chief Executive Officer, Chief Financial Officer, Controller and any other person performing a similar function. These individuals are setting an example for other employees and are expected to foster a culture of transparency, integrity and honesty. Compliance with this code is an essential condition of employment for the financial officers and any violations will be met with immediate sanction.

A complete copy of the Baytex corporate governance policies can be found on the Baytex website at www.baytex.ab.ca or by contacting the Investor Relations Department of Baytex.

BAYTEX DISTRIBUTION REINVESTMENT PLAN

Effective October 18, 2004, Baytex implemented a Distribution Reinvestment Plan ("DRIP"). The DRIP provides a convenient mechanism for unitholders to reinvest their monthly cash distributions in additional trust units. The DRIP permits the purchase of Baytex trust units from treasury at a discounted price. This plan is currently only available to Canadian resident unitholders.

The benefits to eligible Baytex unitholders under the DRIP are:

- Trust units purchased from treasury under the DRIP will be issued at a five percent discount from the weighted average closing price of the trust units on the Toronto Stock Exchange. In instances where Baytex elects to purchase trust units for the DRIP through the facilities of the Toronto Stock Exchange, rather than issuance from treasury, the price of trust units to participants will be the average market price of trust units during the period of up to 20 trading days following the relevant distribution record date. Generally, Baytex expects to issue trust units from treasury at the five percent discount to satisfy the requirements of the DRIP.
- Participants in the DRIP do not pay brokerage commissions or any costs associated with the administration of the plan. However, unitholders who enroll in the DRIP through a broker, trust company, bank or other nominee may be subject to fees in accordance with their agreement with their nominee.

Statements of account are mailed to each participating registered unitholder on a quarterly basis detailing the investment made on their behalf.

Beneficial owners of trust units whose trust units are not registered in their own names may participate in the DRIP by either: (a) having their trust units transferred into their own names or (b) by instructing their broker, trust company, bank or other nominee to participate in the DRIP on their behalf while maintaining the trust units in their nominee's account. **It is not necessary for beneficial owners of trust units to remove their trust units from their account with a broker or other nominee to enroll in the DRIP.**

Canadian unitholders may join the plan at any time by completing an enrollment form, or by having their nominee complete an enrollment form, and submitting it to Valiant Trust Company at 310, 606 – 4th Street S.W., Calgary, Alberta T2P 1T1 Attention: Income Trust Department Fax: (403) 233-2857. A detailed explanation of the terms and conditions of the DRIP and related enrollment forms are available on the Baytex website at www.baytex.ab.ca or by contacting the Investor Relations Department toll free at 1 (800) 524-5521 or (403) 269-4282.

Baytex Energy Trust has a formal policy to conduct its operations in a manner designed to protect the health and safety of its employees, contractors, and the public and to avoid an adverse impact on the environment.

In support of this policy, Baytex Energy Trust:

- has developed and maintains health, safety and environmental management plans which include practices and procedures that comply with regulatory requirements and industry standards;
- ensures that all employees and contract personnel understand their responsibilities through education, communication and training;
- has developed and maintains a contractor management program to ensure contractor and subcontractor compliance with Baytex policies;
- conducts regular review of the safety and environmental management system and conducts updates as required. Input from employees is encouraged and is considered when conducting reviews;
- conducts regular inspections and audits on all properties operated by Baytex; and
- has developed emergency response plans and employees have been trained to effectively respond to emergency situations.

Management is responsible for establishing health, safety and environmental policies and procedures and ensuring that all necessary resources, equipment and training is provided. In addition, corporate safety and environmental reports are presented on a quarterly basis to the Board of Directors. All employees and contractors must understand and comply with all applicable policies and procedures.

In addition to the above, Baytex participates in the Canadian Association of Petroleum Producer's Environment, Health and Safety Stewardship Program. This program has been developed to set consistent safety and environmental standards throughout the Canadian oil and gas industry. The program allows industry participants to measure the quality and performance of its environment, health and safety programs against other companies. Baytex is proud to report that it has achieved a "Gold" ranking under this program for four years running.

COMMUNITY

Baytex believes in enhancing the communities where employees live and work. Baytex supports causes and institutions through financial and volunteer efforts. The Trust is very proud of these associations with many not-for-profit organizations. Baytex employs 116 full time office staff in Calgary and 23 full time field staff in other areas of Alberta, Saskatchewan and British Columbia.

Baytex encourages employees to contribute to their communities through volunteer work. Baytex regularly contributes to causes supported by its employees. Baytex also directs funding to non-profit organizations located in its key operational areas.

Baytex conducts a portion of its operations on aboriginal lands. Baytex maintains a mutually beneficial business relationship with the First Nations communities on these lands and the Trust is proud of these associations.

PRIVACY

Baytex respects and upholds an individual's right to privacy and to protection of personal information. Baytex is committed to ensuring compliance with applicable privacy legislation.

We do not use or disclose personal information for any purpose other than that for which it was collected, with consent or as required by law. Personal information is retained only as long as is necessary for the fulfillment of the purposes for which it was collected, or as required by law.

Baytex protects personal information with appropriate security safeguards including physical, administrative, and electronic security measures.

FINANCIAL

($ thousands, except per share amounts)	2005	2004 (3)	2003 (3)	2002	2001
Petroleum and natural gas sales	**546,940**	420,400	403,022	372,037	338,686
Cash flow from operations (1)	**227,465**	136,012	138,233	191,086	144,070
Per unit/share – basic	**3.38**	2.17	2.56	3.65	2.91
Cash distributions	**114,221**	113,063	33,382	–	–
Per unit	**1.80**	1.80	0.60	–	–
Net income (loss)	**79,876**	16,764	34,141	41,706	(140,454)
Per unit/share – basic	**1.19**	0.27	0.63	0.80	(2.84)
Capital expenditures, net	**152,449**	280,666	48,383	126,468	375,853
Total net debt	**418,476**	422,044	213,572	362,775	379,061
Total assets	**1,105,567**	1,104,136	982,640	997,760	967,046

OPERATIONS

Production					
Light oil and NGL *(bbl/d)*	**3,842**	2,172	2,273	3,154	5,152
Heavy oil *(bbl/d)*	**21,265**	22,703	23,911	23,967	26,533
Total oil and NGL *(bbl/d)*	**25,107**	24,875	26,184	27,121	31,685
Natural gas *(MMcf/d)*	**60.4**	54.9	63.0	72.6	70.8
Oil equivalent *(boe/d @ 6:1)*	**35,177**	34,022	36,686	39,214	43,488
Reserves (2)					
Crude oil and NGL *(Mbbl)*					
Proved	**80,373**	65,933	62,987	104,584	110,221
Probable	**29,882**	27,908	25,350	25,637	26,167
Total	**110,255**	93,841	88,337	130,221	136,388
Natural gas *(Bcf)*					
Proved	**125.5**	111.0	81.2	75.6	134.7
Probable	**50.9**	44.1	24.6	13.5	21.4
Total	**176.4**	155.1	105.8	89.1	156.1
Wells drilled (gross)					
Oil	**64**	104	173	106	63
Gas	**41**	16	67	51	81
Other	**4**	7	7	3	3
Dry	**9**	11	19	26	32
Total	**118**	138	266	186	179

(1) Cash flow from operations is a non-GAAP term that represents cash generated from operating activities before changes in non-cash working capital and other operating items. The Trust's cash flow from operations may not be comparable to other companies. The Trust considers cash flow a key measure of performance as it demonstrates the Trust's ability to generate the cash flow necessary to fund future distributions and capital investments.

(2) Reserves information from 2001 to 2002 is prepared in accordance with National Policy 2-B. Probable reserves presented herein for those years represents 50 percent of the total probable reserves then assigned to allow more appropriate comparison with probable reserves under NI 51-101 as at December 31, 2003.

(3) Restated due to retroactive adoption of the fair value method of estimating compensation expense.

BOARD OF DIRECTORS

Edward Chwyl (2) (3)
Chairman of the Board
Independent Businessman

John A. Brussa (2)(3)
Partner
Burnet, Duckworth & Palmer LLP

W. A. Blake Cassidy (1)
Retired Banker

Raymond T. Chan
President and CEO
Baytex Energy Trust

Naveen Dargan (1) (2)
Independent Businessman

R. E. T. (Rusty) Goepel (1)
Senior Vice President
Raymond James Ltd.

Dale O. Shwed (3)
President and CEO
Crew Energy Inc.

(1) Member of the Audit Committee
(2) Member of the Compensation Committee
(3) Member of the Reserves Committee

OFFICERS

Raymond T. Chan
President and
Chief Executive Officer

W. Derek Aylesworth
Chief Financial Officer

Randal J. Best
Vice President,
Corporate Development

Ralph W. Gibson
Vice President, Marketing

Anthony W. Marino
Chief Operating Officer

Shannon M. Gangl
Secretary
Partner
Burnet, Duckworth & Palmer LLP

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Fax: 403-205-3845
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Toll-free: 1-800-524-5521

AUDITORS

Deloitte & Touche LLP

BANKERS

The Toronto-Dominion Bank
BNP Paribas (Canada)
National Bank of Canada
Royal Bank of Canada
Union Bank of California

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP

RESERVES ENGINEERS

Sproule Associates Limited

TRANSFER AGENT

Valiant Trust Company

EXCHANGE LISTING

Toronto Stock Exchange
Stock Symbol: BTE.UN

New York Stock Exchange
Stock Symbol: BTE

Designed and produced by:
The Design Centre of Canada.
Printed in Canada.

ADVISORY AND ABBREVIATIONS

ADVISORY

Certain statements in this report are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995. Specifically, this report contains forward-looking statements relating to Management's approach to operations, expectations relating to the number of wells, amount and timing of capital projects, foreign exchange rates, interest rates, worldwide and industry production, prices of oil and gas, heavy oil differentials, company production, cash flow, debt levels and cash distribution practices. The reader is cautioned that assumptions used in the preparation of such information, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect. Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: general economic, market and business conditions; industry capacity; competitive action by other companies, fluctuations in oil and gas prices; the ability to produce and transport crude oil and natural gas to markets; the result of exploration and development drilling and related activities; fluctuation in foreign currency exchange rates; the imprecision of reserve estimates; the ability of suppliers to meet commitments; actions by governmental authorities including increases in taxes; decisions or approvals of administrative tribunals; change in environmental and other regulations; risks associated with oil and gas operations; the weather in the Trust's areas of operations; and other factors, many of which are beyond the control of the Trust. There is no representation by Baytex that actual results achieved during the forecast period will be the same in whole or in part as those forecast.

ABBREVIATIONS

API	American Petroleum Institute
bbl	barrel
bbl/d	barrel per day
Bcf	billion cubic feet
*boe**	barrels of oil equivalent
*boe/d**	barrels of oil equivalent per day
Capex	capital expenditures
FD&A	finding, development and acquisition costs
F&D	finding and development costs
GAAP	generally accepted accounting principles
G&A	general and administrative
GJ	gigajoule
LLB	Lloyd Light Blend
Mbbl	thousand barrels
*Mboe**	thousand barrels of oil equivalent
Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
MMbbl	million barrels
*MMboe**	million barrels of oil equivalent
MMBtu	million British Thermal Units
MMcf	million cubic feet
MMcf/d	million cubic feet per day
NAV	net asset value
NGL	natural gas liquids
NYMEX	New York Mercantile Exchange
RLI	reserve life index
WTI	West Texas Intermediate

** BOEs may be misleading, particularly if used in isolation. In accordance with NI 51-101, a BOE conversion ratio for natural gas of 6 Mcf : 1 bbl has been used, which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.*

BAYTEX

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